IOWA UTILITIES BOARD
Policy Development Section

Docket No.: NOI-2014-0001
Utility: Distributed Generation
Memo Date: August 14, 2014

TO: The Board

FROM: Brenda Biddle
Parveen Baig
Leslie Cleveland
Jamie Krieg
Barb Oswalt
Gary Stump
Don Stursma

SUBJECT: Recommendation to Solicit Additional Responses Regarding Net Metering and Interconnection of Distributed Generation and Schedule a Workshop for Distributed Generation Checklist

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I. Background

On January 7, 2014, the Iowa Utilities Board (Board) issued an order commencing an inquiry into distributed generation (DG), inviting participants to comment on broad general questions related to the benefits and challenges of DG, both for utilities and their ratepayers, on policies that should be examined with respect to DG, and to identify the technical, financial, regulatory, and safety aspects of DG that participants would like to address in this inquiry docket. Participants were also invited to comment on other issues they considered relevant to any discussion regarding DG, such as whether there were any technical hurdles to implementing DG. The Board also welcomed any policy recommendations for the Board, other state agencies, or the General Assembly to consider. Comments were received from over 170 participants, including utilities, utility associations, environmental groups, renewable energy advocates, energy-related organizations, businesses, and individuals.

Because of the breadth of topics identified by participants in the initial comments, the Board, in its May 12, 2014, Order, suggested the inquiry focus on the topics of net metering (excluding avoided cost issues, which are the subject of a separate investigatory docket, Board Docket No. INU-2014-0001); interconnection of DG (including safety and reliability); and customer awareness/protection. The Board requested the parties respond to specific questions outlined in the order. Responses were due June 24, 2014.

The analysis portion of the memo is divided into four major sections - Net Metering, Interconnection, Customer Awareness/Protection, and General. Within each section, the participants' responses are summarized by question and, where applicable, include a list of additional questions staff proposes seeking further comment. Appendix A contains a list of 47 participants that responded to the Board’s May 12, 2014, Order and provides acronyms used to identify participants where applicable.

II. Legal Standards

A summary of the net metering and interconnection statutes and Board rules is provided below.

Alternate Energy Production (AEP) Net Metering Policy

Iowa's AEP statute[1] does not explicitly authorize the Board to mandate net metering; however, this authority is implicit through the Board's enforcement of Public Utilities Regulatory Policy Act of 1978 (PURPA) and the AEP statute.

[1] Iowa Code §§ 476.41 - 476.45 was enacted in 1983. The statute’s stated purpose was to encourage AEP development by requiring utilities to purchase electricity from AEP facilities at special incentive rates that would be just and reasonable for utility ratepayers.

Using this authority, the Board has required rate-regulated utilities to offer net metering to AEP facilities.

The Board's net metering subrule 199 IAC 15.11(5) describes net metering service as "a single meter monitoring only the net amount of electricity sold or purchased." The AEP customer draws electricity from and provides excess electricity back to the utility over the same meter making the meter run both forward and backward, thus netting one against the other. This "netting" of AEP kWh production against retail kWh usage is economically equivalent to the AEP customer selling electricity back to the utility at the utility's retail rate. However, net metering does not involve separate purchase and sale transactions – net metering is essentially a metering arrangement that nets kWh against kWh. Also, since net metering involves a single meter, it does not allow for the netting of an AEP facility's kWh production against retail kWh usage from multiple separate meters.

The Board adopted the net metering subrule in 1984 as part of its AEP rules (Docket No. RMU-83-30). In describing the applicability of its AEP rules, the Board drew a clear distinction between renewable AEP facilities and non-renewable PURPA qualifying facilities (QFs) (or cogeneration), explaining why the rules (including net metering) would apply only to AEP facilities. Initially, the net metering subrule applied to all electric utilities. However, in the court challenge of the AEP statute, the Iowa Supreme Court ruled in 1987 that the Board's AEP requirements (including net metering) could not be applied to non-rate-regulated utilities (i.e., municipal utilities and rural electric cooperatives (RECs)).

In 1999 in a renewed court challenge by MidAmerican Energy Company (MidAmerican), the Polk County District Court stayed the Board's net metering rule based on federal preemption. Separately, the Federal Energy Regulatory Commission (FERC) declined to rule that federal law preempted the net metering rule (FERC Docket No. EL99-3). To resolve the litigation and the conflicting results, MidAmerican proposed a settlement net metering tariff supported by the Office of Consumer Advocate (Consumer Advocate) (Docket No. TF-01-293). The main features of the MidAmerican settlement tariff: 1) limited net metering to 500 kW of capacity per AEP facility; and 2) carried forward any net excess generation for net metering in future months, rather than purchasing it from the AEP facility. The Board approved the settlement tariff with modifications. Later, the Board approved a similar net metering tariff for Interstate Power & Light Company (IPL) (Docket Nos. TF-03-180 and TF-03-181).

The Energy Policy Act of 2005 required state commissions to consider implementing five additional ratemaking standards under PURPA Section 211, one of which related to net metering. In an order issued on August 8, 2006, (Docket No. PURPA Standard 11 (199 IAC 15.11(5)), the Board explained that it had considered and adopted, in prior state actions, a net metering standard for

Iowa's rate-regulated electric utilities, having previously made specific policy determinations in various dockets that were consistent with the description of net metering under the PURPA Standard. The Board had defined "eligible on-site generating facilities" as being limited to AEP facilities; and for MidAmerican and IPL, the Board had further limited the definition to a 500 kW cap per AEP facility and had added a requirement to carry forward net excess generation for net metering to future months, consistent with the PURPA Standard.

QF and AEP Interconnection Policy

The Energy Policy Act of 2005 required state commissions to consider implementing the PURPA Interconnection Standard, which required utilities to interconnect any customer's on-site generation (i.e., DG) with the utility's local distribution system, based on the Institute of Electrical and Electronics Engineers (IEEE) Standard 1547 and established non-discriminatory practices and procedures that promote the best practices of interconnection of DG. In an order issued April 25, 2007 (Docket No. NOI-06-4), the Board noted that the PURPA Interconnection Standard had three parts. The first part required the Board to consider broadening its interconnection requirements to include all forms of customer-owned on-site generation, not just QFs or AEP facilities. The Board declined to adopt this part of the Standard but continued examining it as part of its ongoing inquiry. The second part of the Interconnection Standard required the Board to consider adoption of IEEE Standard 1547. The Board noted that it had considered and adopted this standard in a prior rule making (Docket No. RMU-04-6). The third part of the Standard required the Board to consider revising its interconnection rules to reflect current best practices for interconnection agreements and procedures. The Board declined to adopt this part of the Standard but continued examining it as part of its ongoing inquiry.

As a result of its inquiry, the Board initiated a proposed rule making (Docket No. RMU-2009-0008) to further consider the PURPA Interconnection Standard. On May 26, 2010, the Board adopted final interconnection rules for QFs and AEP facilities rather than all forms of on-site generation. The Board clarified that the technical standards of interconnection would be based on IEEE Standard 1547 (i.e., involving revisions to rule 199 IAC 15.10 applicable to all utilities, and an identical parallel new rule 199 IAC 45.3 applicable to rate-regulated utilities only), and that the rules incorporating current best practices for interconnection agreements and procedures (199 IAC 45) would apply to rate-regulated utilities only.

The Board's chapter 45 interconnection rules (199 IAC 45) are designed to offer standardized and streamlined requirements, forms, and procedures for smaller facilities, and to make the interconnection process more transparent and less complex for larger facilities. The rules provide four levels of review:

> Level 1 Expedited Review - For smaller lab-certified, inverter-based facilities with a nameplate capacity of 10 kW or less, which require no

upgrades of the utility's distribution system. This level involves limited insurance requirements, limited application fees ($50), and streamlined standard application forms and contracts.

Level 2 Expedited Review - For larger lab-certified facilities with a nameplate capacity of 2 MW or less, which require no upgrades of the utility's distribution system. This level involves limited insurance requirements (for facilities 1 MW or less), higher application fees ($100 + $1 per kW), and standard application forms and contracts.

Level 3 Expedited Review - For non-exporting, lab-certified facilities, which require no upgrades of the utility's distribution system. This level involves higher application fees ($500 + $2 per kW), and standard application forms and contracts.

Level 4 Review - For all other interconnections. This level involves higher application fees ($1,000 + $2 per kW), standard application forms and contracts, and prescribed studies for determining any potential adverse system impacts and remedies (i.e., Feasibility Studies, System Impact Studies, and Facilities Studies). QFs and AEP facilities are required to pay all study costs and the costs of any required upgrades of the utility's distribution system.

Rule 45.13 requires rate-regulated utilities to file annual reports providing information about each of the utilities' completed interconnection requests, including the final outcome.

III. Analysis

A brief overview of the parties' responses for each Board question posed in the May 12, 2014, Order is provided here. A more complete summary of the participants' responses is provided in Appendix C.

Net Metering (Barb and Leslie)

1. Various commenters recommended net metering policy changes which are listed below. Discuss the advantages, disadvantages, and the regulatory changes necessary to implement each suggested change.

The Board asked the NOI participants to respond to five potential changes that could be made to the net metering policy. In response to this question, MidAmerican, IPL, the Iowa Association of Electric Cooperatives (IAEC), and Iowa Association of Municipal Utilities (IAMU) first discuss their general concerns with making these changes before providing specific answers to each suggested change.

MidAmerican explains there are underlying legal issues surrounding net metering in Iowa that should be considered before making any changes to net metering. Most of the policy options the Board wants commenters to address would extend net metering beyond MidAmerican's Rate NM[2] of QFs, beyond the parameters of the current approach (one customer/one site) of Rate NM, and may be subject to the jurisdiction of FERC over wholesale power before they can be implemented in Iowa.

In addition to potential federal jurisdiction issues, the Board should consider the impact of assigned exclusive electric service territory on the provision of electric utility service in Iowa. Certain options could compromise this system. To the extent any extension of net metering would involve a utility distribution system, such as virtual net metering or aggregation of front-of-the-meter load, it may not be consistent with Iowa's system of coordinated, cost-effective electric service.

The Board also should determine that DG rates should not involve subsidization of DG customers by other customers or by the utility. Net metering makes the assumption that the value of every kWh of net metered generation delivered to the grid is equal to the rate that the net metered customer avoids paying for bundled electric service provided by the utility. There is no link between the value of a kWh of unscheduled DG energy to the grid and MidAmerican's revenue requirement. To note, the number of customers and amount of net metering resources were few and limited when FERC indicated that it would not exert jurisdiction over individual homeowners and farmers who net metered.[3]

IPL believes it is important to have a clear understanding of the rate design that is inherently attached to net metering both today and in the future. "The impact of DG under net metering is a function of both the metering/billing configuration and rate design."

The current Board rules on net metering were the result of a negotiated settlement that resolved a potential contested case about net metering. Net metering was not designed to define the value of a particular DG resource, nor created as an efficient long-term pricing system assuming a larger penetration of DG. Something other than the existing net metering policy is likely needed as a long-term solution.

IPL does not believe it is appropriate to expand net metering beyond its current use in Iowa unless its existing inequities (as an economic pricing approach) are addressed. Net metering provides a payment for DG at the retail rate paid by the

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[2] MidAmerican's Rate NM reflects the resolution of a settlement of litigation regarding the Board's ability to order rate-regulated utilities to net meter as upheld by FERC.
[3] MidAmerican Energy Co., 94 FERC ¶ 61,340 (2001).

customer, an approach where there is an under-recovery of the fixed costs from the DG customers. IPL believes that DG can be more equitably promoted through a cost-based approach, rather than a net metering approach given the current potential for increasing penetration of DG installations in the marketplace and the decreasing costs of DG technologies.

Finally, IPL suggests that a policy goal be defined before making net metering policy changes such as to maximize deployment of cost-effective renewable generation.

The IAEC notes the impact of net metering depends on a utility's rate design and rate structure. Therefore, any net metering policy needs to consider the existing rate structure and potential concerns for a utility to fairly recover its costs from its customers.

Lastly, the IAMU states its most significant concern is the need to retain control of the decisions made regarding DG.

To note: Staff provides brief conclusions at the end of each suggested change and, in some cases, proposes additional questions for the participants.

a. Increase the size cap from 500 kW to 2,500 kW or 5,000 kW.

IPL, the IAMU, the Iowa Industrial Energy Group (IIEG), and John Carpenter state they do not support increasing the size cap. IPL explained that the Board's past position is that net metering is practical for small customers installing renewable generation but not for large customers and that IPL's shareholders could be exposed to significant costs[4]. IPL believes that the Board's rationale is still valid.

The IAMU states that an increase cannot be applied uniformly to municipal utilities since the majority have less than 10 MW of peak demand while very few have less than 50 MW of peak demand; Missouri River Energy Services (MRES) states that municipal utilities can better respond to their unique demographics; therefore, they should determine the appropriate cap size. The municipal utility needs to decide how much net metering should be allowed on its system in order to minimize rate impacts on non-DG customers through cost-shifting.

The IIEG believes that cross-subsidization would quickly grow if the cap size increases.

[4] IES Utilities Inc. and Interstate Power Company n/k/a Interstate Power and Light Company, Docket Nos. TF-03-180 and TF-03-181, "Order Approving Tariffs with Modification and Granting Waiver," p. 5, 1/20/04.

MidAmerican states that the Board should recognize that the size cap was set at the 500 kW level because FERC said it would not assert jurisdiction over homeowners' installations or individual farmers' installations. However, the Board could increase the size cap through a Board order (assuming FERC does not take jurisdiction if changed), but before implementing such an increase, the Board should make sure that the non-DG customers are not subsidizing the DG customers, a concern shared by the IIEG.

The IAEC believes that there could be new challenges to the legality of the net metering requirement under PURPA if the cap size were to change. It also believes that the precedent set in the net metering settlement with IPL and MidAmerican where the Board could not apply its AEP rules to municipal utilities and RECs is still valid today.

Farmers Electric Cooperative – Kalona believes that caps should be a function of technical reality instead of a regulated or rate requirement, and net metering system size is restricted by the demand rate structure through the return on investment for the generation owner.

Several commenters[5] support increasing the size cap because it would encourage additional renewable energy among other things. Luther College specifically explained that it would like to produce all of its own power. However, to do this, the cap must be increased to 5,000 kW. Finally, both the Alliance for Solar Choice (TASC) and ELPC et al. (Environmental Law and Policy Center, Iowa Environmental Council, Sierra Club, Iowa Solar Energy Trade Association (ISETA), Solar Energy Industries Association, the Vote Solar Initiative, and Interstate Renewable Energy Council) explain that a size cap may not be necessary if, instead, the size of the DG is limited to the amount needed to offset the customers' load (TASC) or 100 to 120 percent of customer consumption (ELPC et al.). TASC supports a 2 MW cap if the Board determines a cap size is necessary.

Staff Comments

Staff finds there are three basic issues with increasing the cap size beyond its current level of 500 kW. First, there are jurisdictional concerns. As pointed out by MidAmerican, the level was set at 500 kW because FERC said it would not apply its jurisdiction over net metering for homeowners and individual farmers. However, if the Board increases the cap size to levels proposed by some of the commenters (i.e., 2,500 kW or 5,000 kW), jurisdictional issues may arise with FERC. Second, generally the utility companies have concerns with cross-

[5] The Environmental Law and Policy Center, Iowa Environmental Council, Sierra Club, Iowa Solar Energy Trade Association (ISETA), Solar Energy Industries Association, the Vote Solar Initiative, and Interstate Renewable Energy Council (ELPC et al.), ISETA, Midwest Cogeneration Association (MCA), All Points Power, Energy Consultants Group, Luther College, Luther College Wind Energy Project, the Alliance for Solar Choice (TASC), Winneshiek Energy District , Industrial Energy Applications, and Ben Grimstad.

subsidization where the amount of costs that non-DG customers are subsidizing for DG customers will rise as the allowed size of DG increases. Lastly, IPL points out that historically the Board supports only offering net metering to small customers. Increasing the size cap to the levels suggested by the various commenters would open net metering to large customers as well.

b. Allow "virtual net metering" where a customer who is not personally able to own a DG facility could invest in a DG facility and receive a benefit from the energy produced by that facility.

IPL, MidAmerican, the IAEC, the IAMU, and MRES agree that allowing virtual net metering may create various issues such as:

- IPL believes that virtual net metering allows a DG facility to wheel power over transmission and distribution lines and both the user and generator avoid paying the costs to use the system. It also believes that under Iowa Code § 476.1, a jointly-owned renewable system may be considered a public utility. The limited exemption is if the facility serves five or fewer customers either by secondary line or from an AEP facility or small hydro facility from electricity that is produced primarily for the person’s own use. According to IPL, virtual net metering may require a change to Iowa’s laws regarding the definition of a public utility as well as Iowa’s exclusive service territory laws. Additionally, virtual net metering fails simple economic pricing parameters.

- MidAmerican believes that virtual net metering is prohibited by Iowa law since there is retail wheeling of energy across a utility’s facilities by someone other than the utility. This conflicts with the Iowa service territory statutes. MidAmerican also argues it will increase the amount of cross-subsidization.

- The IAEC states that accounting issues could be created if a customer’s load is located in one service territory, but the DG facility is located in another. Also, the distribution line is being used between generator and the user without adequately compensating the utility.

- The IAMU suggests that billing under these arrangements could be complex and costly.

- MRES expressed several concerns with virtual net metering including: 1) it further complicates the issue of the utility’s obligation to provide reliable service even though the DG customers’ electricity requirements change; 2) providing upgrades necessary to take power; 3) paying for power even if not needed; 4) there are issues with wheeling power over transmission lines and distribution lines and how to allocate those costs; 5) how the transaction is dealt with at Midcontinent Independent System Operator (MISO); and 6) how to deal with congestion on the system.

Both IPL and the IAEC explained that, in essence, virtual net metering can be provided by the utility. IPL provides opportunities for a customer to support renewable energy by offering Second Nature™, and customers can purchase renewable energy certificates through the Midwest Renewable Energy Tracking System (MRETS®). The IAEC states that a DG facility can sell its output to the utility and a DG customer can receive its share of the sales proceeds. There is no need to allow virtual net metering. The IAMU also points out that at least one municipal utility offers virtual metering.

ELPC et al., Iowa Solar Energy Trade Association (ISETA), Midwest Cogeneration Association (MCA), Winneshiek Energy District, All Points Power, Energy Consultants Group, Luther College, Industrial Energy Applications, Moxie Solar, Decorah Solar Field, and several individual participants support including virtual net metering, and many felt that this will help expand the number who could participate in DG. MidAmerican, ELPC et al., All Points Power, Industrial Energy Applications, and Luther College said that virtual net metering makes DG more economically viable.

Finally, MidAmerican acknowledges that virtual net metering could result in better utilization of tax credits for utility and maybe third-party ownership of solar installation, offer DG participation to customers unavailable to own DG on their own premises, and allow DG facilities to be placed in areas where power flows would be less of a concern.

Staff Comments

As with the size cap, staff points out there appears to be issues with offering virtual net metering as part of the net metering policy. The most predominant issue is whether it is possible to offer virtual net metering under existing laws. Because some parties believe wheeling retail power over the utilities' transmission and distribution lines could be prohibited by Iowa law, adding virtual net metering to the current net metering policy may require a change in Iowa law. MidAmerican points out that virtual net metering could increase the amount of cross-subsidization under the current net metering rules.

Staff proposes the following questions for non-utility commenters:

1. Many of the utilities state there are legal issues associated with virtual net metering if retail energy from an off-site DG is wheeled over the utilities' systems.
    a. Do you agree? Explain.
    b. If yes, provide examples of how other states that offer virtual net metering handle these legal concerns expressed by the utilities in this NOI.

2. Is virtual net metering necessary if the utilities offer mechanisms for their customers to participate in renewable energy programs as discussed by IPL and the IAEC?

c. Include combined heat and power (CHP) and waste heat and power (WHP) as net metering eligible facilities.

IPL believes the Board's policy has been to consistently provide net metering for small renewable (AEP) facilities. Currently IPL's existing CHP customers are very large industrial customers taking service under IPL's Standby and Supplementary Service tariff. Extending net metering to CHP customers could significantly negate provisions of the Standby tariff, and given the size of these QFs, the delivery of excess CHP power may actually be considered a wholesale transaction subject to FERC jurisdiction. The rate paid to these facilities under net metering could be considered an incentive rate preempted under PURPA.

MidAmerican also discusses legal concerns with including CHP and WHP in net metering such as: 1) it is unclear whether CHP and WHP are within FERC's expectation of permissible net metered facilities, and 2) Iowa's AEP facilities definition does not include CHP and WHP facilities.

MidAmerican suggests that if the Board determines that CHP and WHP should be eligible for net metering, the rate should be restructured to eliminate increased cross-subsidization that will occur. MidAmerican recommends retaining the 500 kW size cap for these facilities as well as requirements that the net metering be at one site primarily to serve the owners. Use of standby tariffs is more appropriate for larger customers pursuing CHP and WHP.

The IAEC members that offer net metering do so to all eligible facilities which may include CHP or WHP facilities as long as they are not ineligible due to size or other characteristics.

The IAMU states the value of CHP and WHP generation varies greatly depending on a wide range of factors such as size, availability, value of capacity on peak, and cost of upgrading a distribution circuit to accommodate the facility.

MRES expressed concern about the potential impact that CHP or WHP could have on the system. MRES further states that because the customer-owners would be the ones to deal with any inefficiencies or costs, it should be up to the customer-owners as to how CHP or WHP projects would be integrated into the utility.

ELPC et al., MCA, Winneshiek Energy District, Industrial Energy Applications, and John E. Carpenter support including CHP and WHP as an eligible facility in the net metering rules. ELPC et al. explain that it supports improving the methodology of determining avoided costs, improving standby tariffs, including CHP in energy efficiency programs, and exploring state tax incentives.

MCA believes that to encourage small CHP and WHP projects they need to be included in the list of eligible facilities. Otherwise, they have to enter into complicated purchase power agreements. Industrial Energy Applications states that changes in the Iowa Code and utility tariffs might be needed so smaller projects (and perhaps projects which are not on adjacent properties, but are within distances to share thermal outputs) can benefit from these arrangements.

Finally, Luther College states that current high demand standby and tariff charges make including CHP and WHP as net metered eligible facilities unattractive to ratepayers in Iowa.

Staff Comments

Staff notes that as with increasing the cap size and including virtual net metering, there are potential legal issues with including CHPs and WHPs as eligible facilities within the net metering rules as well as potential cross-subsidization issues as well.

Staff proposes the following question for the utilities:

3. Several commenters believe that including CHP and WHP projects as eligible facilities in the net metering rules would encourage the development of small CHP and WHP projects. Assuming it is legally possible, would you object to including these types of projects as facilities eligible for net metering if they fall under the 500 kW size cap? Explain why or why not.

Staff proposes the following questions for non-utility participants:

4. MidAmerican suggests that if CHP/WHP facilities were considered eligible for net metering, the Board should retain the 500 kW size cap and that they be at one site, used primarily to serve the facility owner as it is in its Rate NM. Comment on this.

5. As with virtual net metering, there are legal issues discussed by both IPL and MidAmerican such as whether the delivery of excess power from a CHP facility would be considered a wholesale transaction subject to FERC jurisdiction and that CHP and WHP facilities are not included in Iowa's AEP definition. Comment on this.

6. MidAmerican and IPL believe that it is more appropriate for larger CHP and WHP facilities to be under the standby tariff. Do you agree? Explain why or why not.

d. Allow an annual cash-out of the net metering balance.

Most commenters on this topic support a cash-out of the net metering balance. Some of the RECS and municipal utilities already offer cash-out as an option. However, MidAmerican, ELPC et al., and TASC do not explicitly support this option. MidAmerican believes that the purpose of a net metering arrangement is for customers to self-supply. Therefore, there should not be a large balance to cash-out. However, if the Board were to approve an annual cash-out, MidAmerican supports a 5 percent cap of a customer's annual DG production to prevent net metering participants from overbuilding. Others also discuss caps such as IPL mentioning a 10 to 20 percent cap, Winneshiek Energy District suggesting a cap without specifying a level, and Luther College recommending a limit of 120 percent of total annual compensation. In addition, the IAEC warns that the cash-out option could have the effect of allowing customers to oversize DG facilities. All Points Power supports an annual cash-out because it would incent customers to optimize the DG capacity for installations rather than installing only the capacity needed by the facility.

MRES does not believe a rule change is needed to allow an annual cash-out by municipal utilities.

TASC believes the current indefinite roll-over of net metering credits is sufficient and should be maintained. This approach creates customer incentives to limit the size of a DG system to serve no more than the customer's long-term on-site energy needs, avoiding the need for specific system size limitations that may reduce self-supply opportunities for some customers. By not cashing out, the customer avoids adverse tax and regulatory consequences that occur when energy is sold as part of the net metering arrangement.

ELPC et al. support allowing customers to roll their credits over into the following year. It suggests that customers need to be aware of both federal and state tax consequences if they cash-out net metering balances.

IPL supports monthly cash-out at the avoided cost rate, because banking of excess kWh for use in future months can actually compensate a customer in excess of the full retail rate depending upon when the power was initially received by the utility. IPL also favors a change to the rule to allow net metered kWh (generation greater than use) to be considered a cost of purchased power recoverable through the energy adjustment clause.

MidAmerican suggests that the cash-out option may convert the net metering arrangement to a wholesale transaction which would require FERC approval. Assuming this is not the case, the Board could allow cash-outs of net metering balances through a Board order. Others recognize that the current avoided cost methodology allowing for the payment to facilities that have excess generation under PURPA rules could be extended to DG customers. Industrial Energy

Applications believes that these payments should take into account the value of on peak versus off peak production.

Of the commenters that discuss how to pay out the excess balance, it appears the ISETA is the only one that suggests the excess generation be paid at the retail price to spur DG growth in Iowa.

Staff Comments

Whether or not to allow DG customers the option to cash-out their excess generation balance is the least controversial proposed change to the net metering rules. Most support this change. Some of the RECs and municipal utilities currently offer this option or require their customers to cash-out. According to MidAmerican, this net metering arrangement could be considered a wholesale transaction which would require FERC approval.

Staff proposes the following additional questions:

7. MidAmerican states that a cash-out option may require FERC approval because it may be considered a wholesale transaction instead of a net metering arrangement. Do you agree? Explain.

8. Some commenters recommend setting a cap on the amount of cash-out the customer could receive.
    a. Do you agree that a cap is needed?
    b. If yes, at what level and why that level?

9. If the customer is allowed to cash-out the net balance, should it be:
    a. On a monthly basis or an annual basis? Explain why.
    b. Required or optional? Explain why.

10. Comment on the potential impact of IPL's suggested rule change that would consider net metered kWh as a cost of purchased power recoverable through the energy adjustment clause.

11. Although there was no consensus, the commenters discussed whether a cash-out rate should be based on the utility's avoided cost rate or the utility's retail rate. Explain which one you believe is the appropriate rate and why.

e. Include aggregate metering for customers who may have more than one meter on their premises.

The commenters addressing this question either support meter aggregation or do not explicitly object to it with the exception of the municipal utilities who state that aggregate net metering exacerbates concerns of a one-size-fits-all approach for municipal utilities. Many assumed aggregate metering meant multiple meters on the same premise, and MidAmerican assumed the aggregation is behind the meter because otherwise it would be considered retail wheeling, but also added that FERC may consider aggregate metering to be a wholesale sale of power.

If there are no applicable legal issues, MidAmerican believes efforts should be made to ensure meter aggregation does not result in preferential treatment under standard filed rates. For example, combining usage on more than one netted meter should not allow a customer to move from a medium to a large volume rate. MidAmerican also recommends that DG customers install their own distribution facilities to combine separate loads so that they flow through a single meter which would eliminate unlawful retail wheeling using MidAmerican facilities.

IPL suggested that a customer with multiple meters can own the secondary transformation and secondary lines outright moving the metering to the high side of the customer-owned transformer. Another option is the customer can pay IPL an excess facilities charge for the dedicated distribution facilities to allow for metering consolidation. These considerations are needed otherwise customers will want aggregated metering across multiple facilities without covering the related costs.

According to the IAEC there is nothing in PURPA or Board rules precluding a DG customer from serving multiple loads on its own premises, as long as the DG customer is generating primarily for its own use. However, aggregate net metering essentially allows a customer to use the utility facilities when neither Iowa law nor PURPA require a utility or allow said DG customer to use the facilities to provide such service. The concept of aggregate net metering calls into question whether or not net metering can continue to be treated as a metering arrangement instead of a purchase and sale.

According to the Iowa Nebraska Equipment Dealers Association (INEDA), aggregated net metering is an arrangement that does not require a physical connection between the system and multiple meters in order for a single generating system to be used to offset energy used on multiple meters. It is simply an administrative function to apply net excess kWh to separately metered accounts for customers like agricultural producers. INEDA suggests the Board consider Interstate Renewable Energy Council (IREC) Net Metering Rules, 2009 edition as a template for meter aggregation as well as rules from Minnesota, Illinois, Arkansas, and Colorado. Finally, it points out that aggregate net metering does not create cost shifting; net metering costs are already "baked-in" to the current electric rates.

ELPC et al. believe there are no physical or technical reasons to prohibit aggregate metering for these customers. Customers can realize economies of scale by aggregating several loads and offsetting them with a single DG facility.

MCA recommends a public rule making docket to determine how aggregation will be implemented.

All Points Power and Industrial Energy Applications point out that IPL already offers this for large industrial customers so it should be able to offer aggregate metering to all customers.

Staff Comments

Staff believes generally there is little opposition to aggregating meters. Although, MidAmerican and IPL believe that the multiple meters need to be connected while INEDA does not. MidAmerican also states that FERC would consider meter aggregation as retail wheeling unless it is behind the meter and the utility's distribution system is not used. However, IPL provides an alternative that the customer can pay IPL for the use of the utility's distribution facilities needed to aggregate the meters. Staff has the following questions to address these differing opinions.

12. IPL and MidAmerican discuss connecting the meters on a DG customer's premises in order to aggregate meters, while Iowa Nebraska Equipment Dealers Associations believes no physical connection is necessary. Comment on this.

13. MidAmerican suggests that meter aggregation needs to occur behind the meter and the utility's distribution system cannot be used to aggregate the meters; otherwise, FERC would consider it retail wheeling. Do you agree? Explain why or why not.

2. How does the utility account for energy "purchased" through net metering when reporting fuel type information to the Board, the United States Energy Information Administration, the Federal Energy Regulatory Commission, and others?

IPL, MidAmerican, Farmers Electric Cooperative – Kalona, and ELPC et al. agree that there is not a purchase through net metering; the IAEC more specifically states that no fuel type is reported. However, the IAMU states municipal utilities report the annual net amount of energy sold back to the utility on the U.S. Energy Information Administration's (EIA) Annual Electric Power Industry Report (Form EIA-861).

To have more accurate reporting to the Board, the EIA, and FERC, IPL supports a change to 199 IAC 20.9(2) reflecting all energy produced in excess of that consumed by the customer be considered an energy purchase.

Staff Comments

Staff believes that since there is no reporting of "purchases" through net metering, this question has been answered, and no further inquiry is needed. However, staff proposes the following question regarding IPL's proposed change to 199 IAC 20.9(2):

14. For more accurate reporting to the Board, the U.S. Energy Information Administration, and FERC, IPL suggested changing 199 IAC 20.9(2) to reflect that all energy produced in excess of that used by the net metering customer would be considered an energy purchase. Do you agree with this suggested change? Explain your response.

3. Provide a list of the REC and municipal utilities who currently offer net metering. Also provide the applicable tariff or policy describing the net metering option.

According to the utility associations, 23 members of the IAEC offer net metering in their tariffs, 17 members of the IAMU offer net metering, and none of the 19 Iowa member communities of the MRES offer net metering. The IAMU also notes that a total of 32 municipal utilities have DG facilities interconnected. MRES purchases energy or capacity from any QF that offers to sell the energy or capacity based on FERC rules and consistent with PURPA using rates based on avoided costs as defined by PURPA.

ELPC et al. comment that REC and municipal utility net metering policies vary by utility and are not transparent or easy for a customer to access or understand. EcoWise Power mentions that: 1) MidAmerican and IPL customers have an advantage over REC and municipal utility customers in regards to incentives and opportunities for DG systems; 2) many RECs offer net-metering programs, but have restrictive policies regarding use; 3) installers would be a good source of information and be able to provide valuable insight into establishing DG systems in Iowa; and 4) Iowa needs to establish a statewide policy to establish consistent DG rules and policies.

4. For the REC and municipal utilities currently offering net metering, how do customers learn about the net metering program? For the REC and municipal utilities that do not offer net metering, explain why net metering is not offered.

The IAEC states that members likely learn about net metering via communication with the REC, member-owner inquiries, and from individuals selling DG facilities. It is likely that net metering is not offered due to lack of interest. Financial impacts vary by utility and net metering may not be feasible for all locations.

According to the IAMU, information is available from utilities on request and may be on the utility or city web site. The IAMU developed a model net metering policy for members to use which is accelerating the adoption of policies. Through net metering, generation is purchased at the retail rate which includes energy and distribution costs, and therefore, higher energy costs. Avoided cost rates would prevent cross-subsidization.

The reasons MRES-member utilities do not offer net metering include cost concerns, rate structure fit, and lack of local interest.

Energy Consultants Group believes there is a lack of awareness among customers about availability and options.

5. Currently Iowa does not offer feed-in tariffs (FITs). Explain why you think FITs should or should not be implemented in Iowa. In your discussion, address the advantages and disadvantages of both net metering and FITs.

There is no consensus on the issue of whether FITs should be implemented in Iowa. Several parties comment that local utilities should decide whether to offer a FIT. MidAmerican adamantly opposes implementing FITs in Iowa, and the IAMU opposes mandatory implementation. Energy Storage Association (ESA) suggests including behind-the-meter storage in the net metering rules as an alternative. Several non-utility participants support implementing FITs in Iowa. Two parties suggest conducting studies of FITs.

IPL defines a FIT as a policy mechanism designed to accelerate investment in renewable energy technologies. This is a policy question for the state of Iowa to consider along with Iowa's current renewable generation position, declining costs of DG, and customer equity questions.

MidAmerican states that FITs should not be implemented in Iowa. FITs typically involve long-term contracts with fixed-rates set above avoided costs. This effectively shifts economic risk from the supplier to the purchasing utility and its customers resulting in higher energy supply costs. If the State decides to encourage these types of facilities it would be better accomplished through expanded use of tax credits, etc. that provide direct, defined benefits to facility owners. In order to have multi-tiered avoided costs, it appears that the Board would need to create an additional renewable portfolio standard (RPS), an action the Board could take on its own. While a FIT sounds like an innocuous regulatory action, the Board would exceed its statutory authority and violate PURPA if it were to adopt a FIT without a new RPS. MidAmerican believes that Iowa has demonstrated that substantial renewable assets can be built without the mandate of a large RPS obviating the need for a law providing for a FIT.

The Consumer Advocate states that both FITs and net metering are policies adopted to encourage DG. A leading argument against FIT legislation proposed in Iowa has been that the Board's net metering rule already addresses compensation because there is less need for FITs in jurisdictions where net metering is widely available. The Board's net metering rule is limited to the service territories of Iowa's rate-regulated utilities, although a number of RECs have voluntarily adopted some form of net metering. It could be challenging to develop a FIT policy regarded by interested stakeholders as both effective for encouraging renewable DG and compliant with federal law. Generally, a FIT can more precisely recognize unique generation characteristics that are to be taken into account in avoided cost pricing and can be adjusted to reflect changing avoided cost factors and methodologies. California's FIT program recently adopted market-based prices. Competitive procurement methods were recently adopted in Maine, Oregon, Rhode Island, and Vermont.

According to Farmers Electric Cooperative – Kalona, implementing a FIT improves DG by allowing for more accurate measuring than net metering, and providing full accountability of financial benefits for the buyer and seller. The requirement of a separate meter allows for the tracking and monitoring of energy for systems analysis, reliability issues, environmental attributes, engineering studies, and more. Rates can be structured, regulated, adjusted, and could eliminate cross-subsidization inherent to net metering.

The IAEC suggests that there may be questions whether the Legislature has granted the Board authority to fund FITs and whether the funding for FITs would come from the tax structure or Board assessments. Existing incentives allow entities to invest in a DG system with very little capital risk. Additional incentives may have an unbalanced effect on utilities and could impact low-income users.

The IAMU states that municipal utilities support DG incentives when costs are fairly allocated and value is accurately accounted but are opposed to a mandatory FIT because customers are then paying the incentive to other customers and the incentive may encourage DG growth beyond the utilities' supportive capacity. Municipal utilities support optional separate tariff rates for DG, but local control over design of individual FITs should be retained by the utility.

MRES comments that FITs are not necessary in Iowa to incentivize renewables. Any decision on FITS should be kept local in order to address the issues such as cost shifting, technical aspects, safety and reliability. The decision to offer a FIT and at what rate should be a decision made by customer-owners and municipal utilities. Failure to address coordination in planning, interconnection, and deployment of DG resulted in costly infrastructure upgrades in Germany to handle the load and other technical challenges. A mandated FIT is contrary to PURPA avoided cost requirements.

TASC believes that prices set for FITs can be too high or too low and can ultimately prove to be an unstable program to support DG system development. FITs relative to net metering have significant tax disadvantages that include potentially jeopardizing access to tax credits and possibly having to be included in a taxpayer's reported taxable gross income.

As a general rule, ELPC et al. recommend policymakers make an effort to provide customers with choices and options so that they can select programs that work best for them. FITs require an administrative determination to set the appropriate price which has proven challenging in many cases. If the rate is too high or too low the result could be either a stunted market or an overheated market either of which creates a difficult situation for growing a sustainable market. A FIT may be less appealing to investors because it may change periodically depending on how it is structured. Deployment of a new FIT can spark rapid market growth (if that is one of the goals of the program) providing a boost to net metering in markets where retail rates are lower than would be necessary to increase market growth on their own. The FIT program can then be scaled down in a transparent way to provide a bridge to a longer-term sustainable DG market based on net metering. Net metering preserves a customer's ability to self-supply using on-site generation which is important to some customers and businesses. In contrast, FITs are typically structured as a wholesale transaction in which the customer sells or is credited all of their on-site energy production. FITs can also have tax consequences which are important to consider.

ELPC et al. contend that net metering has supported customer generation in states that have healthy and growing DG markets. It is important to preserve and expand net metering in Iowa at this critical stage of market development. FITs and other appropriately designed regulatory programs should be explored as supplements to a strong net metering program to more quickly ramp up the DG market in Iowa. Long-term, more sophisticated policies and regulatory tools could be developed in the context of a comprehensive regulatory process that considers the paradigm shift to a more decentralized electricity grid.

ESA does not take a formal position on net metering policy; each state has its own regulatory construct with commensurate rules and policies that enable DG. Net metering cannot simply be replaced with a FIT. A FIT enables long-term certainty of price but does not account for daily price differentials. Any tariff would need to account for services for both injection and withdrawal, and generally a FIT accounts only for injection. ESA recommends instead that net metering rules include behind-the-meter storage which could prove useful in scaling on-site storage as well as in fully realizing the benefits of solar rooftop systems and other distributed energy resources.

The IIEG believes that FITs should not be implemented in Iowa due to concerns that the associated costs would be paid by non-participating energy consumers and would subsidize the installation of DG through FITs. The terms FIT and incentive rate have been used interchangeably in this docket. A FIT has come to encompass any agreement for the purchase of electricity that includes a fixed price, a set duration, standard terms and conditions, and the right of a seller to interconnect to a utility's delivery system. An incentive rate could represent anything ranging from a tariff-based credit for interruptible rates to a full-blown FIT. Incentive rates usually involve a price signal based on a utility's existing rate structure reflecting the cost of conventional generation whereas, electricity prices included as part of a FIT are typically based on the costs inherent in the particular form of alternative energy under consideration and may have no relationship to the generation cost, a utility's tariffed rates, or power prices in established energy markets, such as MISO in Iowa.

According to the IIEG, net metering offers two distinct advantages over FITs: 1) the amount of energy produced under net metering arrangements is generally limited to the amount of energy a participating customer requires; and 2) net metering arrangements have a built-in ceiling for the price of electricity produced, namely, the retail rates charged by the utility and approved by the Board (for rate-regulated utilities). In some jurisdictions, FIT arrangements have been established that allow participants to sell more energy to utilities than is needed for additional capacity and at either wholesale or retail prices. FIT systems in Spain, Germany, and Canada all opened with high participation, but due to the disproportionate rates resulted in negative impacts on non-participating ratepayers.

MCA encourages the Board to consider a FIT program for CHP and WHP projects. Net metering is a stream-lined mechanism for transmitting relatively small amounts of excess power from DG utility customers back to the grid whereas FITs provide a streamlined approach for larger DG projects and for encouraging the development of larger CHP and WHP projects. FITs provide transparent project parameters that allow prospective developers to plan and assess projects.

The Sierra Club – Iowa Chapter states that FITs promote DG by providing for a long-term fixed contract that may be used by a renewable energy owner as collateral for a loan. FITs benefit both the utility and the DG owner by setting fixed prices for fixed periods. In contrast, net metering has the advantage of reducing the owner's energy bills but does not help with equipment expenses. FERC has made it clear that a state can make separate avoided cost calculations if the utility is required to purchase electricity from different sources.

According to Winneshiek Energy District, net metering and FITs are both attempts to fairly value DG and compensate owners. FITs have been used internationally in support of renewable energy policy goals and normally have fixed prices and time periods. Net metering is simpler resulting in a 1:1 production/consumption bill credit. Winneshiek Energy District supports further study into development of a FIT in Iowa suggesting if/when it is implemented that net metering should continue to be an option at the residential and small commercial level for DG customers.

Ben Grimstad believes that FITs should be considered if they will encourage more DG. Decorah Solar Field LLC, Frank Belcastro, Jason Hall, Jean Marie Hall, Jenn Hall, Kami Ahrens, Larry A. Stone, Tim Brodersen of Moxie Solar, and William H. Ibanez agree that both FITs and net metering encourage local DG development and allow for a faster transition to renewable energy. Wendy VanDeWalle states that FITs and net metering are great DG incentives. William J. Pardee states that the community would benefit from a FIT assuring an adequate return when energy production exceeds consumption.

All Points Power states that an advantage of FITs is the certainty that excess power produced by a DG source will result in known cash flows, encouraging system design based on load as opposed to minimizing expense associated with electrical production. A disadvantage is consistency and scheduling complications for utilities.

Farm Energy believes FITs should be offered by rate-regulated and non-rate-regulated utilities to all independently-owned DG facilities in Iowa. Tariff rates should be technology specific and reflect reasonable rate of return, inflation, deferred transmission needs, reduced peak energy costs, environmental benefits, etc. Net metering should be offered as well, but there are specific advantages to FITs. DG facilities using a FIT would pay income tax on their system profits addressing concerns about lowered state revenue resulting from increased net metering installations. FITs also address aggregate meter concerns and provide a fair system for both business and residential customers.

Both FITs and net metering are good incentives to encourage solar growth. Based on some of the challenges and growth fluctuations seen by Germany's FIT system, Energy Consultants Group believes that net metering appears to be the more appropriate long-term choice. A study should be conducted to determine feasibility of a combination FIT and net metering system in Iowa.

John E. Carpenter states that the principal advantage of a FIT is that it incentivizes renewable energy development. The system in place in Germany should be researched to see a working model and build a development plan. A disadvantage of FITs is that the costs may fall on other customers and the utility.

FITs and net metering facilitate a quicker transition to renewable energy by providing financial incentive to encourage local investment in DG which will help Iowa transition to clean renewable power. Chris Hoffman of Moxie Solar states that the current avoided costs system discourages this growth.

FITs establish a known rate for excess energy produced by DG, without the need, expertise, and expense to negotiate a separate power purchase agreement (PPA) with the local utility. Industrial Energy Applications states that a disadvantage is that the utility will have to purchase more power which will be harder to schedule but that this can be overcome with planning, customer interface, and real-time production data.

FITs and net metering provide an incentive for participation in DG. Robert Fisher states that the advantage of a FIT would be that it allows the system owner to install a system large enough to generate more than 100 percent of their own requirements and receive a return on the surplus.

Steven Demuth believes that Iowa should implement a system of FITs that are fair to DG facilities and to Iowa's electrical utilities. Pure net metering without constraints is not sustainable if DG is widely adopted, because it does not fully reflect the costs of distributed power. This can be avoided through FITs that are properly constructed. The Board should adopt policies that strongly encourage utilities to adopt smart metering and real-time pricing of electrical usage by all consumers and extend these policies with appropriate FITs that likewise reflect actual value of generation with an allowance for utility line loss and overhead.

Staff Comments and Recommendation

There is no consensus among the commenters whether FITs should be adopted in Iowa. There are legitimate legal arguments that adoption of a FIT policy would violate PURPA because Iowa has not adopted an RPS beyond that found in Iowa Code § 476.44(2). FITs are often seen as an alternative to net metering. Iowa has had net metering in place for rate-regulated utilities (and several non-rate-regulated utilities have adopted net metering policies on a voluntary basis). Because of the significant federal jurisdictional issues associated with adopting a FIT policy and the numerous issues that are being addressed in this DG inquiry, staff recommends that discussions of this issue be tabled at this time.

6. Comment on whether you believe the Board has jurisdiction to extend the net metering requirement to coops and municipal utilities and if so, whether it should exercise such jurisdiction.

There is also no consensus among the participants on the issue of whether the Board has jurisdiction to extend net metering requirements to RECs and municipal utilities. Generally, the individual participants believe that the RECs and municipal utilities should be required to offer net metering. The IAMU and MRES both specifically state that the Board does not have jurisdiction to extend net metering to RECs and municipal utilities in Iowa.

The Consumer Advocate states that if current policies in non-rate-regulated service territories are insufficient to support renewable DG, the Board should take action to address the policy gap. The Consumer Advocate further states that Board authorization to require non-rate-regulated utilities to interconnect customer-owned DG was addressed in Docket Nos. NOI-06-4 and RMU-2009-0008. The Board's goal in the rule making was to facilitate the addition of DG at the distribution level. The Board indicated it would closely monitor the practical application of the rules and may propose amendments if the adopted rules are not working as intended to facilitate the interconnection of DG facilities. The Board declined to extend the application of the rules to non-rate-regulated utilities at that time indicating that it may revisit the jurisdictional issue if needed. The Board's broad oversight authority, combined with the 2005 Energy Policy Act mandate to encourage renewable energy, support a finding that the Board should consider whether current policies in service territories served by non-rate-regulated utilities are sufficient to support renewable DG. If not, the Board should take action to address the policy gap.

The IAEC states that the Iowa Supreme Court noted that federal law gives non-rate-regulated utilities broad discretion to implement PURPA, and concluded that a non-rate-regulated utility's decision to not offer net metering was lawful. The Court concluded that it would be erroneous for the Board to attempt to impose such a requirement. FERC stated in a 2004 Order that it has never claimed PURPA requires net metering. FERC also expressed the opinion that PURPA would not preempt a state legislature from requiring a utility that is otherwise unregulated to net meter. To date, neither state nor federal law currently mandates net metering for non-rate-regulated utilities. The IAMU and MRES also believe that the Board does not have jurisdiction over REC and municipal utility rates; and that federal law points to a hands-off approach when it comes to non-public utility rates.

ELPC et al. provided a jurisdictional history and states that net metering and interconnection standards are within the limited jurisdiction the Board has over RECs and municipal utilities. Iowa law provides the Board with authority and the policy imperative to apply net metering to RECs and municipal utilities. Customers should not be deprived of the opportunity to self-generate and net meter solely because they are served by an REC or municipal utility. The Board should exercise its jurisdiction and expand net metering to cover RECs and municipal utilities.

The Sierra Club - Iowa Chapter also believes that the Board has jurisdiction to require RECs and municipal utilities to provide net metering and FITs but is not suggesting that the Board establish rates and fees in requiring FITs and net metering for RECs and municipal utilities. It seems clear that customers of one utility should not be disadvantaged and discriminated against in relation to customers of another utility. This is especially true considering a customer has no choice in his or her electricity provider. The Board certainly has the authority to prevent discrimination against customers who want to use renewable energy. See Iowa Code § 476.21. Additionally, the Board could request that the legislature grant the Board authority to regulate RECs and municipal utilities. Prior to the 1986 legislation, Iowa Code §§ 476.1A and 476.1B, the Board, or its predecessor, did have that authority. These utilities would then no longer be classified as non-regulated under PURPA.

Steve Demuth and Ben Grimstad favor the Board extending net metering requirements to RECs and municipal utilities if the Board has jurisdiction to do so.

Energy Consultants Group, Farm Energy, John B. Cook, Decorah Solar Field LLC, Frank Belcastro, Jason Hall, Jean Marie Hall, Jenn Hall, Kami Ahrens, Larry A. Stone, Moxie Solar,and William H. Ibanez support the requirement for RECs and municipal utilities to offer net metering and generally believe the Board has the authority for such a requirement.

Staff Comments and Recommendation

Staff used the information provided in response to Question 3 to determine that 12.5 percent (17 out of 136) of the municipal electric utilities and 52.3 percent (23 out of 44) of the RECs offer net metering. The average number of residential customers served by the 119 municipal utilities that do not offer net metering is 841 whereas the average number of residential customers served by the 21 RECs that do not offer net metering is 2,380.

Based on the utilities' annual report filings with the Board (IE-1, EC-1, and ME-1) and responses to Question 3[6], staff calculates that approximately 88.8 percent of Iowa's residential customers (approximately 1,191,000 customers) have access to net metering with 11.2 percent (or 150,089) of residential customers served by a utility not having net metering. The table below details this information.

	Avg. # of Residential Customers in 2013	Avg. # that have Access to Net Metering	% that have Access to Net Metering
Investor-Owned Utilities	966,951	966,951	100.0%
Municipal Utilities	176,991	76,889	43.4%
Electric Cooperatives	197,168	147,181	74.6%
Total	**1,341,110**	**1,191,021**	**88.8%**

Staff observes that a number of RECs and municipal utilities offer net metering and a large percentage of Iowa residential customers have access to net metering. The Board's net metering rules currently only apply to rate-regulated utilities. While some commenters urge that the rules be applied more broadly, staff observes that several RECs and municipal utilities have net metering policies and does not recommend that the Board seek to assert jurisdiction over

[6] The calculation assumes that if a municipal utility or REC reported that they have net metering, it is available to all residential customers. The calculation does not consider limitations (i.e. maximum amount of DG/customers on their system) in place at each REC or municipal utility.

non-rate-regulated utilities' net metering policies at this time. The Board could revisit the issue if more RECs and municipalities do not adopt net metering practices on a voluntary basis.

7. If you believe that net metering results in cross-subsidization of DG customers by non-DG customers, how should the net metering rule be revised to reduce or eliminate such cross-subsidization?

Note: Because both Questions 7 and 8 address the issue of whether there is cross-subsidization with respect to DG, staff's recommendation is provided at the end of the staff summary for Question 8.

The utilities, along with some other commenters[7], argue there is cross-subsidization of DG customers by non-DG customers using the current rate design. The current pricing structure recovers most fixed charges through the volumetric rate. Therefore, DG customers that zero out the energy they use in a given month do not pay for the system needed to provide them service. These costs are shifted to non-DG customers. Both IPL and MidAmerican agree that changes to the pricing structures may be necessary, and IPL suggests that DG customers have their own customer class. This is consistent with the Board rules for load research found in 199 IAC 35.9(2) and would reduce the chance of cross-subsidization between DG customers and non-DG customers.

According to IPL there are two approaches to minimize subsidies while collecting the embedded costs necessary to serve the DG customer. IPL suggests either increasing the fixed customer charges and/or instituting demand charges.

MidAmerican believes that by implementing demand rates and time-of-use (TOU) energy rates for residential and small commercial DG customers, the cross-subsidization problem could possibly be eliminated. The distribution and transmission service costs could be collected in the demand charge instead of in the volumetric charge. MidAmerican points out that a change in the net metering rules is not required to implement demand/TOU rates for DG customers. The Consumer Advocate and a couple of individual commenters also suggest rate design or policy changes.

The Consumer Advocate also mentions adopting TOU rates for net metered customers to minimize cross-subsidization. TOU rates properly reflect the utility's marginal cost of energy since costs vary by season and by the time of day, can help reduce usage during peak period, and can produce pricing signals that enhance resource planning and allow the utility to focus on procuring generation resources with better output efficiencies. John B. Cook recommends utilities charge a flat grid connection fee to cover the cost of maintaining the grid,

[7] Frank Belcastro, William H. Ibanez, Jason Hall, Jean Marie Hall, Jenn Hall, Kami Ahrens, Larry A. Stone, and Moxie Solar.

and Steve Demuth suggests adopting policies that clarify the degree of cross-subsidization and phase out such subsidization over a period of time.

The IAEC believes the Critical Consumer Issues Forum principles are a good starting point for revising the net metering rule to reduce or eliminate cross-subsidization.

MRES claims that the Board does not have jurisdiction over rate structures for non-public utilities, and any changes to the net metering design should be left to the local municipal utility.

The IIEG believes that the costs of a residential customer's net metered facility should not be recovered by customers in the commercial or industrial rate classes.

Commenters, such as TASC and ELPC et al., suggest that a comprehensive study should be done before claiming there is cross-subsidization. Some studies have shown net benefits from DG customers to non-DG customers. The remaining commenters[8] believe that no cross-subsidization exists, that DG provides benefits for society/all customers, and/or cross-subsidization is not an issue if all customers have the option to participate in virtual net metering. Many argue that DG reduces the need for building new plants, increases the reliability of the grid, and reduces line losses. In addition, the Sierra Club - Iowa Chapter stated that energy efficiency is not accused of cross-subsidization, and renewable energy is no different than energy efficiency in that respect.

8. If you believe that net metering does not take into account the benefits that DG provides to non-DG customers, how should the net metering rule be revised to account for such value?

IPL, the Consumer Advocate, and MRES believe that net metering does not lend itself to determining the benefits that DG may provide, because net metering is not designed to measure output at the generator (IPL) or recognize societal and environmental benefits (Consumer Advocate). Additionally, the Consumer Advocate states that in the aggregate, net metering programs sufficiently recognize the benefits and savings to the system. It is best to use a FIT designed as a technology-specific avoided cost rate to explicitly compensate renewable DG for societal and environmental benefits.

[8] MCA, the Sierra Club, Winneshiek Energy District, Decorah Solar Field, All Points Power, Frank Belcastro, Jason Hall, Jean Marie Hall, Jenn Hall, Kami Ahrens, Larry A. Stone, Moxie Solar, Energy Consultants Group, Luther College, John E. Carpenter, Industrial Energy Applications, Robert Fischer, William H. Ibanez, William J. Pardee, Ben Grimstad, and Steve Demuth.

According to MidAmerican, the DG customers that take service under energy only rates are over-compensated for the limited benefits that may be provided to the non-DG customers. The benefits that may be provided would likely be in the form of generation benefits. Therefore, demand/TOU rates should be used where TOU rates would give appropriate price signals to DG customers regarding the value of the energy and capacity their DG facilities provided.

The IAEC is not aware of any necessary change to the REC's net metering policies regarding this question; the IAMU suggests that a value of solar tariff could be a fair method of compensation and eliminates the cross-subsidization concerns; and MRES argues that there are concrete costs and stranded costs associated with DG if a resource is added to the utility that is not part of the utility's resource planning model, which are paid by other customers.

Non-utility commenters had the following suggestions:

- Steve Demuth - Net metering should be based on metering of consumption and generation at the service entry; utilities should be permitted to impose a reasonable rate adjustment on generation to the utilities' costs for supporting DG.

- William J. Pardee - Net metering compensation should not be limited to 100 percent of energy used; the rate should be adjusted upward reflecting the reduction of fossil fuel costs and the value of time-of-day production.

- The Sierra Club - Iowa Chapter - Each customer should pay a flat rate for basic services that are required for the utility, be charged fuel costs based on the amount of electricity used, and charged for transmission and distribution based on the amount of electricity they purchase. Also, a customer who has DG equipment should be charged for the use of the transmission and distribution lines when they deliver power to the grid.

Both ELPC et al. and TASC believe a comprehensive study is needed as mentioned under Question 7, but both TASC and ELPC et al. suggest this discussion is premature. TASC states it should be deferred until the market has grown large enough to warrant a comprehensive study. Additionally, since Iowa does not engage in the accounting of the utility specific costs and benefits of net metering systems, there is not enough evidence to answer Questions 7 and 8. ELPC et al. believe there is not enough evidence of cross-subsidization at this time.

Decorah Solar Field, Frank Belcastro, Jason Hall, Jean Marie Hall, Jenn Hall, Kami Ahrens, Larry A Stone, Tim Brodersen of Moxie Solar, and William H. Ibanez argue that net metering provides a benefit to the non-DG customer because it promotes DG using clean power and provides power at high demand times. All customers can participate in net metering through the implementation of virtual net metering. Industrial Energy Applications, John B. Cook, and John E. Carpenter also argue that DG provides benefits to non-DG customers. However, Industrial Energy Applications believes the current net metering rules are sufficient.

Staff Comments

Generally, utilities are concerned about cross-subsidization and with any proposed change to the net metering policy that could potentially increase the level of cross-subsidization. As pointed out by IPL, when net metering was created, its purpose was to encourage DG when participation levels were low. As the level of DG participation grows, the net metering policy as a whole may need to be reviewed. Many agree that there are benefits of DG but they are difficult to quantify, and many agree that in order for DG customers to help pay for the utility's fixed costs, some type of charge should be implemented. Two basic proposals were presented: 1) make rate design changes for the DG customers; or 2) initiate a study looking into the benefits and costs of DG. (As mentioned above, it was recommended waiting until the DG penetration level was high enough to justify allocating resources to do such a study).

Staff recommends including these follow-up questions in a Board order.

15. IPL, MidAmerican, and the Consumer Advocate suggested a rate design change for DG customers such as TOU/demand rate. According to MidAmerican, this would remove any cross-subsidization between DG customers and non-DG customers. Is this a reasonable solution to this issue? Explain.

16. Comment on IPL's suggestion that DG customers should have their own specific customer class for rate design purposes since their load profiles and service needs differ from non-DG customers.

17. Some parties suggest that a study be done showing the benefits of DG compared to the costs of DG to determine if there is cross-subsidization.
    a. Is this an appropriate approach to resolve this issue?
    b. Is this the appropriate time to expend the resources to conduct such a study or should the study be done when DG penetration reaches a level where it becomes a bigger issue for utilities?
    c. Who should perform the study?
    d. Who should pay for the study?

Staff also notes that the cross-subsidization issue is a sub-issue of many of the potential changes to net metering rules discussed above. As those potential changes are considered, cross-subsidization will need to be addressed.

9. For customers who currently use net metering, provide the following information:

a. Type and size of your DG facility;

b. Your electric service provider; and

c. Positive and negative experiences with net metering.

ELPC et al. state that the Board's approach to solicit feedback from customers is a good step; direct outreach to customers and installers will provide a more comprehensive set of responses and experiences. Customers and installers have expressed that their ability to take advantage of net metering varies significantly among RECs and municipal utilities and those who have access to net metering have had positive experiences.

Ben Grimstad, an IPL customer who installed a 5.6 kW roof-mount system in 2012, says that the process was satisfactory, though the paperwork was laborious.

Craig Mosher is a Hawkeye REC customer who installed a 1 kW photovoltaic (PV) system in January 2014 and says net metering is working well. He also notes that paperwork and fees were excessive in establishing the interconnection agreement and the process needs to be streamlined in order to encourage additional DG. Mr. Mosher pays a $27 per month demand charge to be connected to the grid.

Larry Grimstad of Decorah Solar Field uses net metering with three solar facilities. He says that a 280 kW solar array (leased to Luther College) and a 3.5 kW solar array (rental property) are located in IPL's territory and believes arrangements were all positive except for the necessity to establish a lease between Decorah Solar Field and Luther College. He would prefer to receive a cash payment, have a carry over, or bank excess power production. The third facility, a 10 kW solar array installed in 2011, is interconnected to Calhoun County REC. Generally the experience has been positive although the REC did not have net metering available. This system would likely be better off with a FIT under a long-term contract or net metering that does not cash out at year end. Year-end cash out is unfair to solar production since solar generation is lower during the month of January.

Tim Graber is an IPL customer who has four 40 kW solar systems. He believes net metering with banking is critical for farming operations, and the decision to utilize solar energy was to help normalize costs.

Paul Reed is an IPL customer with a 16.96 kW ground mount solar system. Net metering was a very important aspect of the decision to purchase solar systems, and it helps to normalize electrical costs and plan for farming operations.

Porter Farms has five 20.1 kW systems on hog buildings and two 10 kW systems on a home farm. IPL provides service at two locations and Access Energy at five locations. The ability to bank excess power at the IPL locations has helped in the farm budget planning.

Todd Lorack is an IPL customer with a 50 kW system. The system is straight forward, and there have been no difficulties understanding the process or billing.

Darrell Egli is an IPL customer with 10 kW and 67 kW systems. The net metering process is very easy and works well for operations.

JG4 Hog, LLC, is an IPL customer with a 12 kW solar system. The system is straight forward, and there have been no difficulties understanding the process or billing. Net metering was critical in the decision to purchase a solar system; net metering allows better management of contract.

Jason Gideon of Energy Consultants Group is an IPL customer who installed a 6.5 kW DC. The overall experience was good, but the process for interconnection is lengthy and complicated and billing should be simplified.

Luther College owns three solar PV systems (4 kW, 5 kW, and 20 kW) and leases a 280 kW PV. Luther College is an IPL customer, and the experience was positive.

Nixon Lauridsen and Rob Sand are Clarke Electric Cooperative customers and have a 20 kW solar array. The experience has been positive, but Clarke Electric Cooperative does not offer net metering so the price received for electricity sold to the grid is a small fraction of the price at which they are required to purchase it.

Randy Portz of Industrial Energy Applications is an IPL customer who has installed a 3 kW PV panel. The experience was generally positive, but because of the type of metering used by the electric service provider, it is difficult to determine at any point in time how much energy is actually being generated and transmitted to the utility

William J. Pardee is a Hawkeye REC customer who installed a 10.12 kW PV array. The experience has been completely satisfactory.

Staff Comments

Staff notes that this question was asked to determine customers' experiences with net metering. In general, the individuals who responded to this question had favorable comments on their experiences with net metering. Although some support refinement of the financial arrangements, their suggestions have been discussed above. These responses complement responses provided for experience with interconnection process questions.

Several customers mention that net metering is not available from their REC (specifically siting T.I.P. REC and Prairie Electric Cooperative), but staff observes that both were on the list of RECs that the IAEC provided in reference to Question 3 above. Additionally, staff has reviewed the tariffs of these two RECs and found that both do offer net metering. Staff suggests that all utilities, especially T.I.P. REC and Prairie Energy Cooperative, provide customers net metering information that is consistent with their current tariff filings and help customers understand the requirements associated with net metering.

10. Provide the advantages and disadvantages of the current net metering rules. Are there specific changes that need to occur to these rules to encourage additional DG in Iowa?

According to TASC, an advantage to Iowa's current net metering rules is the ability to indefinitely carry forward the allowance for net excess generation. This creates an incentive to the customer to limit the size of the DG system to only what is necessary to meet long-term on-site energy needs. TASC recommends removing size limitations from the current net metering rules to allow customers to better meet their on-site energy needs and encourages the Board to expand net metering to all customers in Iowa, including municipal utilities and RECs. TASC also supports consumer's rights to install self-generation through third party arrangements which can ease the burden of necessary operations and maintenance costs and expands the financing options available to customers. TASC encourages both the Board and the General Assembly to exhaust all actions within their authority to permit a variety of financing tools, including PPAs and leases.

ELPC et al. believe the best option is to maintain Iowa's existing net metering rules while a comprehensive study of DG costs and benefits is completed. Revisiting Iowa's net metering rules should be a data-driven process that supports Iowa's legislative policy goal to encourage alternate energy production. ELPC et al. recommend changes to Iowa's net metering including expanding the cap on the size of facilities eligible for net metering, considering CHP eligibility for net metering, and expanding net metering to RECs and municipal utilities.

Decorah Solar Field LLC, Frank Belcastro, Jason Hall, Jean Marie Hall, Jenn Hall, Kami Ahrens, Larry A. Stone, Moxie Solar, and William H. Ibanez believe the net metering rules should be changed to allow and encourage virtual net metering. Paul Reed and JG4 Hog LLC also support virtual metering because at some locations there are better layouts to put the systems and these systems produce better. Virtual net metering would allow offsetting power needs at all of their locations. According to Energy Consultants Group, virtual net metering is needed in Iowa because countless projects have come up where the customer was dedicated to installing solar but was unable to because of various physical or utility limitations.

Porter Farms, Ben Grimstad, Tim Graber, and Todd Lorack feel net metering rules are meeting their needs.

Atwood Electric states that the REC customers he has talked to would like to have net metering available to them. Duane Atwood, Dennis Hamme, Doug Flynn, Ryan Vogel, Joe Eiben, Jeff Andeway, and John Waltzing would like to install solar but are served by RECs that do not offer net metering. Atwood Electric notes that DG is good for the Iowa economy, can be very good for the grid stability, reduces system losses, and has expedited start to finish construction times.

William J. Pardee understands that if he expanded his DG system so that his electric energy production exceeded his annual energy consumption, the compensation would drop sharply to the avoided cost rate. This rate does not accurately reflect the avoided cost to society achieved by reducing CO_2 production, peak power purchase needs, capital to expand expensive fossil fuel plants, and the increasing externalized costs of extraction, transportation, and consumption of fossil fuel. The compensation rules could use time-of-day metering to reflect the value of peak load power and include compensation for the tons of avoided CO_2 and account for the general societal benefits.

<u>Staff Comments</u>
This question was directed at utility customers, so overall the responses support removing size limitations, extending net metering to REC and municipal utility customers, and allowing virtual net metering. These topics were all discussed under the first net metering question, so staff provides a summary of comments here but refers to the recommendations made above.

<u>Recommendation for Net Metering Issues</u>

There has been much information filed about net metering in this docket, but parties have not had an opportunity to respond to each other's recommendations, proposals, or data reported in response to the net metering questions. Staff recommends the Board allow participants the opportunity to file reply comments. The responses should specify which comment, recommendation, or response to a Board question they are responding to.

Additionally, staff recommends the Board request participants respond to the questions listed above to further explore the various net metering issues.

Staff recommends the Board table the discussion of FITs at this time due to the significant federal jurisdictional issues associated with adopting a FITs policy and the numerous issues that are being addressed in this DG inquiry.

Staff recommends that the Board not assert jurisdiction over non-rate-regulated utilities' net metering policies at this time while continuing to encourage them to adopt net metering practices on a voluntary basis.

NET METERING
RECOMMENDATION APPROVED

IOWA UTILITIES BOARD

/bkb

IOWA UTILITIES BOARD

/s/ Elizabeth S. Jacobs *9-8-14*
Date

/s/ Nick Wagner *9/9/14*
Date

See my additional questions/comments attached

/s/ Sheila K. Tipton *9/10/2014*
Date

<u>Interconnection</u> (Parveen and Don S.)

In some instances the participants' responses have generated additional staff questions. These proposed questions follow staff's overview of the parties' responses.

For the remaining questions, staff does not have additional questions, but is interested in getting feedback from the participants on the various participant's recommendations or comments.

Note: Because both Questions 1 and 7 address the issue of whether the Board's interconnection rules should be revised, staff has combined the participant's responses below.

1. Do the current interconnection rules ensure that DG installations are safe for customers and utility employees? If not, what specific changes are needed to ensure safe installation and operation of DG equipment? Include specific examples of safety problems, if any, and customer or utility behaviors that may compromise safety.

7. Should the Board revise its interconnection rules in 199 IAC 45 to make them consistent with the FERC's updated interconnection rules, which were adopted on November 11, 2013, in Docket No. RM13-2-0001 (Order No. 792) and can be found at 145 FERC ¶ 61,159? In what specific ways should the Board's rules be revised?

Most commenters state that current rules are adequate. However, several commenters recommend the adoption of additional standards. Many commenters suggest that DG installers should be certified but no one suggested who should certify DG installers. Customer education was also suggested as an important issue by two commenters and one customer suggested that the Board's Web site should include DG related information. The issues of installer certification and education will be addressed in detail in this memo in the Customer Awareness and Protection section.

IPL, MidAmerican, the Consumer Advocate, and MCA agree that the current interconnection rules allow for safe DG installations. However, MidAmerican believes there may be a need for periodic inspections after installation to ensure proper upkeep and maintenance. ELPC et al. also recommend incorporating a clearer supplemental review process. IPL comments that after an interconnection request is deemed complete, the utility assigns a review order position based upon the date the interconnection request is determined to be complete, with preference given to existing customers as compared to a new developer who becomes a customer as a result of a DG installation.

The IAEC believes the Board's adoption of various codes as well as other codes and standards provide a foundation for safe interconnections of DG. The IAEC and member RECs have developed model policies to comply with the applicable provisions of the regulations which are included as part of an REC's tariff on file with the Board. Collaborative work needs to continue between the utility, state and local inspectors, customers, installers, and other invested parties. The IAEC suggests that additional information be added to the Board's Web site or that the Board provide information to the public regarding safety of interconnections.

The IAMU supports training and certification for DG installers and electrical inspectors, and developing fact sheets for customers that include certified DG installers.

International Brotherhood of Electrical Workers (IBEW) states that clarity is needed on the following questions to ensure system reliability and safety due to interconnection of DG resources.

- Where are inspectors employed and how are they qualified?
- Does the utility have the opportunity to inspect a DG facility before the final switch is turned on?
- Will there be significant fines for DG installations that have not followed the proper processes?
- Will there be stiffer fines and civil charges for improperly processed DG installations that result in someone's injury or death?

MRES believes the state has adequate safety rules, but there is an issue with enforcement of those rules. State rules need to mandate that qualified personnel are doing electric work and inspections with consequences for failure to abide by those mandates.

IPL also encourages the Board to draw a distinction between a customer and a developer who becomes a customer only as a result of an installed DG system.

MidAmerican believes there are no specific items from FERC's revised rules that require immediate changes to Iowa's interconnection rules. Industrial Energy Applications and All Points Power believe current interconnection rules requiring sign-off by a licensed electrician and inspection by the local utility are adequate for safety to both the customer and utility personnel. Industrial Energy Applications, All Points Power, Jason Hall, Jean Marie Hall, Jenn Hall, Kami Ahrens, Larry Stone, Moxie Solar, and William H. Ibanez recommend that adoption of FERC rules would be counterproductive.

ELPC et al. believe Iowa's current interconnection standards in 199 IAC chapter 45 are working well. However, Iowa should also update its standards to be consistent with FERC's updated Small Generator Interconnection Procedures (SGIP) in anticipation of higher penetrations. ELPC et al. recommend considering inclusion of a pre-application report,[9] modifying Level 2 eligibility requirements,[10] and incorporating a clearer supplemental review process.[11]

In addition to these changes based on the FERC SGIP, ELPC et al. recommend some additional changes based on IREC's Model Interconnection Procedures, which reflect national best practices. Specifically, ELPC et al. recommend increasing the Level 1 review threshold to 25 kW; modifying the "no construction screen" in Levels 1 and 2; eliminating the Feasibility Study; not allowing the utility to require an external disconnect switch for an inverter-based facility; requiring utilities to dedicate a webpage to interconnection; and requiring utilities to allow online applications and electronic signatures to be used for interconnection applications. Finally, ELPC et al. recommend that the Board initiate a rule making to revise Iowa's interconnection standards to incorporate best practices from the FERC SGIP.

Winneshiek Energy District also recommends adopting IREC procedures. IPL partially agrees with ELPC et al. in that IPL believes a pre-application report (as outlined in FERC rules) would benefit all parties. IPL also adds that the report should not be entirely duplicative of FERC rules, because they are broad and not designed to address the direct customer impact of the state's interconnection decisions.

MCA recommends adopting the pre-application report, raising the threshold for the Fast Track application process to 5 MW, revising procedures governing customer options meeting and supplemental review under the Fast Track process, and allowing interconnection customers to provide written comments on upgrades deemed necessary for interconnection. The Sierra Club - Iowa Chapter and Winneshiek Energy District recommend that the Board revise the rules in a similar manner to what Ohio did in response to Order No. 792.

The IAEC adds that the size of generation interconnected under FERC rules most likely will not take place on the DG system the Board has defined for purposes of this docket. The Consumer Advocate recommends reviewing whether Iowa's fees should be restructured to be consistent with FERC's new SGIP fast track process. MRES also recommends considering adoption of the FERC rules as well as IEEE or any other best practices policies. ESA encourages Iowa to adopt SGIP that are applicable to storage projects.

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[9] FERC SGIP § 1.2; see also IREC Model Interconnection Procedures § II; NREL, Updating Small Generator Interconnection Procedures for New Market Conditions 12-15 (Dec. 2012), available at www.nrel.gov/docs/fy13osti/56790.pdf [hereinafter NREL Interconnection Report].
[10] FERC SGIP § 2.1; see also IREC Model Interconnection Procedures § III(B)(2)(a).
[11] FERC SGIP § 2.4; see also IREC Model Interconnection Procedures § III(D).

<u>Staff Comments</u>

Several parties have suggested adoption of additional specific standards and others have recommended additional review processes. Staff believes that it is important to consider whether adoption of the FERC SGIP standards would add value to existing Board rules or would be counterproductive, and what specific standards, if any, need to be adopted. The following questions are designed to gather pertinent information on standards discussed in these comments.

1. Is there a need to adopt FERC SGIP standards as recommended by ELPC et al. and others? Specify sections of the standards that should be adopted and explain the value these sections would bring to the Board's existing rules.
    a. Some parties suggest that adoption of these standards would be counterproductive. Explain why adoption of these sections is not counterproductive.

2. Is there a need to adopt the Interstate Renewable Energy Council's Model Interconnection Procedures as recommended by ELPC et al.?
    a. Explain the additional value these standards bring to the Board's existing rules.

3. Comment on the need to develop a supplemental periodic installation review process after the installation.
    a. What elements (frequency of installation inspection, duration etc.) should be included in the review process?
    b. Who should develop, implement, and conduct the review process?
    c. Do you have any suggestions on which Board rules need revision to incorporate your recommendations?

4. Who has the authority to inspect a DG installation for improper installation, maintenance, or operation? Provide legal standards that apply.

5. Who has the authority to penalize a DG installation for improper installation, maintenance, or operation? Provide legal standards that apply.

6. Comment on IPL's proposal to give preference to existing customers? Explain your response.
    a. What problems would this create/solve?

2. Is there an issue with customer DG installations occurring without the knowledge of the utility? If so, what is the magnitude of this problem, and how should it be addressed?

Several commenters, including utilities, commented that they are aware of instances where DG interconnections have occurred without utility notification, but it is difficult to know the magnitude of the problem. The IAMU states that unknown installations are occurring but it is not a significant problem. Four commenters,[12] including the Consumer Advocate, state that they were not aware of specific issues with DG installations occurring without the knowledge of the utility. Several commenters[13] support training and certification of DG installers to remedy this problem. The commenters' underlying theme is that DG installations should occur with the knowledge of and support from the utility.

IPL mentions that when DG is installed in a service territory that has advanced metering infrastructure (AMI) the utility may become aware of that installation through a metering alarm or because a customer called about a higher than expected utility bill. Wisconsin Power & Light, IPL's sister company, has had several instances where DG was installed and was operating without its knowledge. Its AMI metering has alerted the utility of the presence of DG and Wisconsin Power & Light was able to work with the customer to correct any problems.

MidAmerican suggests that increased public awareness of Iowa's law requiring host utility notification of installation would benefit all. Also, the interconnection rules process may exceed the 30-day advance notice, and it may be beneficial to have a longer notice period.

MRES recommends the Board consider financial penalties or even prohibition on interconnection of such installations. IBEW states that utilities are discovering that DGs have been unknowingly connected. Something needs to be done to prevent this because it puts the lives of utility workers and the public at risk.

<u>Staff Comments</u>
Staff believes that MidAmerican needs to provide additional clarification on why the 30-day notice needs to be extended. Staff has drafted a question for MidAmerican regarding its recommendation to give longer than 30-day notice. Other inquiry participants may also comment on this.

7. For MidAmerican: Provide reasons to extend the notice period, a reference to the notification requirement that you believe needs to be amended, and proposed language changes needed to extend the 30-day advance notice discussed in your response to Board Interconnection Question 2. (Other parties are also encouraged to respond.)

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[12] The Consumer Advocate, MCA, Energy Consultants Group, and ELPC et al.
[13] IPL and the IAEC

3. Are rule changes necessary to ensure system reliability is not harmed due to interconnection of DG resources? Provide specific examples of reliability effects from the interconnection of DG.

The Consumer Advocate, the IAEC, ELPC et al., All Points Power, Energy Consultants Group, and Industrial Energy Applications suggest rules changes are not necessary to ensure system reliability.

IPL, MEC, and the IAMU discuss reliability issues associated with large DG installations. IPL believes there is less impact on short urban feeders which tend to have better voltage support. Following is a list of potential reliability effects from interconnection based on the parties' responses:

- Reverse power flow from DG to the distribution system may damage equipment. Correcting this requires significant investment to ensure reliability;

- Service restoration during outages may take longer as crews assure that DGs on an affected circuit are visibly disconnected;

- High voltages during periods of light load occurring near DGs and nearby customers;

- Voltage step changes occurring when the DG is cycling output (e.g., cloud cover for solar generators);

- Circuit islanding if the sum of the DG output exceeds the load on the circuit;
- Strict settings on DGs exacerbating the under frequency problem during periods of under frequency;

- Blinks in power on system circuits; and

- Connection of DG to dead feeders.

IPL also suggests using smart inverters on new installations is an option to ensure smooth integration onto the electric grid and is evaluating the reliability impact and cost increases from larger DG installation impacts on wear and tear of IPL's system.

MidAmerican believes the interconnection rules provide reasonable methods to ensure reliability in most DG installation scenarios but note that existing rules do not enable review of new developments where the entire development installs solar. A review process would benefit customers and the utility to see if such a development will cause the need for system upgrades where currently the need is discovered when the last customer in the development requests interconnection and is assigned the upgrade cost.

IPL agrees with MidAmerican that large DG customers (500 kW or greater) interconnecting with IPL's distribution system are limiting other generation from being able to interconnect to the system.

MRES believes the interconnection rules should reflect the best practices set forth by the IEEE and/or other relevant sources. Additional safety standards should be allowed as deemed appropriate by each utility based on unique needs and possible impacts to their distribution system. MRES also believes there is a need for rule enforcement and consequences for failure to comply.

Luther College states if there is a 15 percent rule regarding maximum DG input to a feeder line, it should be revisited.

Staff Comments

Staff agrees with commenters in that if there is a potential for a large group of DG customers or a group of several large customers coming on-line in a short period of time and in close proximity to each other, then such installations need to be reviewed in clusters. Specifically how these installations affect distribution feeder loads is an issue that needs to be explored. MidAmerican specifically noted that existing rules do not enable review of new developments where the entire development installs solar. Staff proposes the following questions to the inquiry participants.

8. What, if any, specific Board rule changes are necessary to allow for the study of DG installations in new developments or neighborhood service areas?

9. Is there a need to revisit the 15 percent screen standard discussed in rules IAC 199-45.8(1)a and 45.9(1)a? Explain your response.

10. What are potential impacts of revising the 15 percent limit of the maximum load normally supplied by the distribution circuit to a higher limit?

11. What, if any, higher limit should be adopted? Explain the reasoning (and data) that support why such a higher limit is reasonable.

4. Considering the benefits that accrue to the system from DG, what is the correct price to charge for interconnection of DG systems? Should this price be technology dependent?

Two commenters provide comments on accrued benefits. MCA states that the interconnection agreement is not the proper place to address accrued DG benefits. The monetization of continuous benefits in a onetime payment could underprice accrued DG benefits. MRES states that the benefits of DG and type of technology are irrelevant to interconnection fees. Those who commented on the second part of the question state that prices should not be technology-specific.

Commenters can be divided into two categories on the fees for interconnection; those who state that interconnection costs should be directly assigned to a DG customer and those who believe that the costs be nominal (based on administrative fees). The Sierra Club - Iowa Chapter, John B. Cook, and Chris Hoffman of Moxie Solar believe the cost of interconnection for DG should be zero or nominal. Jason Gideon, Jason Hall, Jean Marie Hall, Jenn Hall, Kami Ahrens, Larry Stone, Tim Brodersen of Moxie Solar, and William H. Ibanez believe the current rates are adequate.

Those that believe the costs should be assigned to the DG customer generally agree that the costs should be based on the direct costs of interconnecting to protect from cost shifts and should not be technology dependent. ELPC et al. state changes to Iowa’s interconnection fees should be based on data demonstrating the utility costs and that the utility has implemented modern practices to minimize interconnection costs.

According to MRES, municipal utilities should set their own rates based on cost and should have the ability to adopt their own interconnection standards. William J. Pardee believes it is fair to charge for the costs of inspection with regards to charging for interconnection of DG systems.

IPL and MEC recommend interconnection costs be borne by the interconnecting customer based on the direct costs of interconnection and should not be technology dependent. The current pricing structure protects other customers from subsidizing the DG installation. The Consumer Advocate and MCA agree with IPL and MEC that the price for interconnection should be based on actual costs to interconnect.

IPL also suggests that the application fees for Level 1 and Level 2 interconnections be revised and recommends that the Board increase the flat fee for these applications to cover actual costs (including the cost of an engineering review and a witness test) estimated at $250.

Industrial Energy Applications and All Points Power believe DG customers should not pay fees associated with obtaining an agreement but that interconnection charges should be based on labor and material expenses incurred by the utility.

The IAEC states that the Board should take care in removing consumer protections provided by PURPA and that the DG owner may be charged the interconnection costs. The definition is flexible enough to allow for separate costs by technology to the extent they differ or the same across technologies if they are the same.

Staff Comments
As background, staff notes that the current interconnection fees were set in Docket No. RMU-2009-0008 and based on fees used in Illinois. During that process, IPL questioned the proposed fees and thought they should be examined to determine whether they addressed the utility's full administrative processing cost. At that time IPL had a flat $280 application fee. In determining the current fees (Level 1 - $50, Level 2 - $100 plus $1/kVA, Level 3 - $500 plus $2/kVA and Level $ - $1,000 plus $2/kVA), staff noted IPL presented nothing to demonstrate the multi-level fee structure in Chapter 45 was unreasonable. None of the other parties opposed the fees.[14]

Staff recommends the Board ask other parties to comment on IPL's proposal to increase the fees to $250 for Level 1 and Level 2 applications.

12. Comment on IPL's proposal to increase the Level 1 and Level 2 application fees to $250.

5. How should distribution or transmission system upgrade costs associated with DG installation be properly allocated? Are there specific benefits that all customers (DG-owning and non-DG owning) receive from DG required transmission or distribution upgrades and, if so, what are the specific benefits?

All commenters acknowledge that there may be transmission and distribution costs associated with DG installations. There is some agreement that system improvements caused by DG benefits other customers. Specific benefits were not identified by any commenter. Commenters did not agree on how these costs should be allocated.

IPL believes that transmission upgrade costs will be incorporated into the MISO transmission planning process. The IAMU agrees with IPL that larger DG projects may require planning studies and in some circumstances MISO planning and study requirements could apply. IPL and MidAmerican agree that upgrades to the system borne by the DG owner provide benefits to others that should be reflected in the price paid by the DG owner. MidAmerican suggests that until there are enough DG customers on the system, a load shape for a DG customer cannot be determined to separate this class of customer to determine cost of service therefore DG-related distribution and transmission system upgrade costs should be treated in the same way that all other distribution and transmission costs are treated for the purposes of cost allocation and rate design.

[14] RMU-2009-0008, May 10, 2010, IUB staff memo, pp. 24-26.

The Consumer Advocate suggests that DG installation costs should be assigned to the interconnecting generator that causes the costs. In specific situations, it would be appropriate to apportion a lesser amount of the costs to the interconnecting DG. The IAEC mentions that the principles outlined in the Critical Consumer Issues Forum provide a good baseline for allocation of costs.

MRES believes the decision on how to allocate costs should be left to the municipal utility and its customer-owners. DG system benefits depend on load and customer profile information.

According to MCA, developer costs and costs of review and processing by the utility need to be cost of service based to hold the ratepayer indifferent. Utilities' planned upgrades should be considered in allocating costs to DG customers. All Points Power and Industrial Energy Applications state that the cost of large systems should be part of the rate paid by customers whereas smaller systems can be assessed as excess facilities charges by the utility.

Energy Consultants Group states that non-DG customers should pay for the fees because they are consuming the excess energy (from the DG) and create the grid demand. A number of other commenters provide different reasons but they all believe that all customers should share in the cost of new transmission lines and upgrades.

The Sierra Club - Iowa Chapter, ELPC et al., Decorah Solar Field, Frank Belcastro, Jason Hall, Jean Marie Hall, Jenn Hall, Kami Ahrens, Larry Stone, Moxie Solar, William H. Ibanez, William J. Pardee, John B. Cook, and ESA believe that all customers should share in the cost of new transmission lines and upgrades but provided different reasons for their position.

Staff Comments

Staff agrees with MidAmerican in that a true cost-of-service study to determine DG rates requires customer class load profiles, and, until there are a sufficient number of DG customers on the system, a class load profile for a DG customer class would be difficult to identify to determine separate class cost allocation. For now, it is reasonable to continue to use direct assignment of these costs. Some of these costs, especially if the interconnection triggers transmission upgrades, may need to flow through MISO transmission rates.

None of the parties identified any specific benefits of DG interconnection. Staff agrees that there may be ancillary benefits to other customers when distribution and transmission system upgrades are implemented when they are triggered by new DG interconnections. However, unless large amounts of DG resources come on line in a short time frame and are installed close to each other, these benefits are not easily quantifiable.

6. Is there adequate protection for distribution assets from improperly installed DG equipment? If not, what additional protections are needed?

MCA identifies additional protection such as utilities can require DG operators to install a lockable external disconnect switch and purchase liability insurance coverage.

IPL believes that voltage control and voltage regulation problems may occur on large systems. MidAmerican states that there is no required periodic inspection or testing that would reduce the potential for adverse effects. John B. Cook states that utilities should supervise and/or make sure installers are qualified.

MRES believes municipal utilities should also have the ability to adopt additional standards and suggests that there be enforcement provisions for failure to comply, including penalties.

Other commenters believe systems can be designed to provide adequate protection for distribution assets to meet the evolving need of the DG systems.

Staff Comments
Responses to this question touch on multiple issues that are covered in other questions. The following question is drafted to cover an issue that is not covered in other sections.

13. Should utilities require DG operators to install a lockable external disconnect switch? Explain your response and provide pros and cons of such a requirement from cost and technology perspectives separately.

Staff Note: Question 7 and the summary of the participants’ responses are listed above with Question 1.

8. Should the Board require any customer installing DG with a view toward selling excess generation to the utility to commit to remaining interconnected for a specific period of time, to maintain the DG system in good working order for that entire time period, and to either obtain a similar commitment from any subsequent purchaser of the property or to remain responsible for the commitment for that entire period of time. If so, why? If not, why not?

Most commenters believe these commitments are not necessary. IPL believes such requirements would be ideal for utilities by promoting long-term interconnection safety and certainty. MidAmerican points out that the DG owner is obligated to operate and maintain interconnection facilities in good working condition. The Consumer Advocate suggests that such commitments may be more reasonable and acceptable for large DG facilities.

The IAEC, the IAMU, and MRES agree that such Board mandates remove the parties' ability to negotiate or the DG owner's ability to make choices about what to do with its generation output. MCA states such regulations could prove onerous and prohibitive for potential clean CHP systems. Winneshiek Energy District doubts that a requirement such as a simple pre-requisite to grid access would hold up in court. MRES adds that it may be appropriate for the state to set minimal requirements such as insurance, disconnect equipment, and planned disconnection/ generation. MCA agrees that commitments are met with liability insurance, disconnect switch requirement, and stand-by rates. All Points Power and Industrial Energy Applications state long-term commitments from only the DG owner are not needed. ELPC et al. agree that instead of long-term commitments from DG owners, the Board should require utilities to evaluate DG as a separate resource option in their resource plans. Luther College comments that such requirements are routine in PPAs and it is not clear that this is necessary today for systems that fall under the current 500 kW net metering limit.

Energy Consultants Group notes that the utility company does not own the equipment and should not be dictating what happens behind the meter. John B. Cook stated that requiring an unreasonable commitment would discourage DG.

Decorah Solar Field, Frank Belcastro, Jason Hall, Jean Marie Hall, Jenn Hall, Kami Ahrens, Larry Stone, Moxie Solar, and William H. Ibanez state that the Board should require a long-term commitment from any customer installing DG with a view toward selling excess generation to the utility. This is necessary to maintain a dependable distribution system.

Staff Comments

Any mandatory requirement that includes long-term commitments would limit the ability of parties to negotiate workable interconnection agreements. It is not feasible for the Board to require specific elements of interconnection agreements. IAC 199-45.17(476) Appendix D standard distribution generation agreement provides basic requirements of an interconnection agreement. These rules have worked well in the past. Staff believes additional Board requirement of long-term commitments by parties is not needed at this time. Detailed elements of interconnection agreements should be negotiated by interconnecting parties

9. For customers that have installed DG, what have been the positive and negative experiences when interconnecting with the utility and what specific changes would you suggest? (Identify whether the DG facility was renewable or nonrenewable and which utility you interconnected with.)

a. Does the interconnection process timeline take longer than necessary? If so, what are the problems and how can they be solved?

b. Has any DG owner-commenter experienced difficulty interconnecting a DG project with the system of any non-rate-regulated utility or utilities? If so, please describe the difficulty experienced and whether/how the difficulty was resolved.

One commenter states that a unified structure with required response times overseen by the Board is needed. Several participants provide specific examples of process delays, and one suggested that there should be a grievance process to resolve disputes. Another customer discussed his positive experience with IPL's DG interconnection process.

Craig Mosher, Decorah Solar Field, Frank Belcastro, Jason Hall, Jean Marie Hall, Jenn Hall, Kami Ahrens, Larry Stone, Moxie Solar, and William H. Ibanez believe the process needs to be streamlined and made more cost effective to encourage more DG. All Points Power agrees and adds that there also needs to be a grievance process to resolve disputes.

Farm Energy's experience is generally positive but mentions that the net metering system seems unfair. Farm Energy also notes that the facility would likely be better off with a FIT under a long-term contract or with a net metering arrangement that did not cash-out at year end.

EPo Energy and Energy Consultants Group state that the majority of the process was timely. Specifically the process with Access Energy was very efficient, but the IPL process was more cumbersome and complex.

Luther College says that the process worked well for its wind and solar projects, though it did seem to take every day allotted for each stage of review.

Industrial Energy Applications suggests that small solar projects should be approved more quickly than the large projects but both seem to take longer than they should to get approved. Additionally, Industrial Energy Applications suggests that utilities need to deploy the appropriate technical resources to avoid delays in the process, and utility staff needs to be more knowledgeable and provide better trained technical support.

Wendy VanDeWalle states that the time table to turn on her solar array with IPL took a week but has heard that it has taken longer for other customers.

Staff Comments

It appears that many times the interconnection process takes longer than necessary from DG owners' perspective. One customer believes that the Access Energy process is efficient and less complex as compared to IPL's process. Another customer discussed his positive experience with IPL's process. Staff believes that this issue relates closely to the public education issue discussed later in this memo. Staff believes customer education is important and with an improved customer education process, interconnecting customers would enter the process with less uncertainty and would be able to navigate the process more easily.

Several commenters agree that some of the process steps take too long. Each utility has designed its steps that constitute the whole interconnection process. Staff believes the timeline for these steps as well as what these steps should be is an issue that needs to be determined by individual utilities. Rule 199 IAC 45.12 (476) contains rules regarding resolution of disputes between interconnecting parties. The Board's complaint process through 199 IAC chapter 6 is also available to resolve complaints. At this time, it is not necessary for the Board to revise its rules related to this topic.

10. Comment on whether you believe the Board has jurisdiction to extend its interconnection rules to coops and municipal utilities and if so, whether it should exercise such jurisdiction.

The IAEC, the IAMU, and MRES believe there is no reason to extend the Board's jurisdiction over interconnection rules to RECs and municipal utilities while IPL and MidAmerican took no position on the question.

ELPC et al., the Sierra Club - Iowa Chapter, Jason Gideon, Jason Hall, Jean Marie Hall, Jenn Hall, Kami Ahrens, Larry Stone, Moxie Solar, William H. Ibanez, and John B. Cook believe the Board has jurisdiction and should exercise jurisdiction to extend the interconnection rules to RECs and municipal utilities.

The Consumer Advocate noted that extending the interconnection rules would ensure common interconnection standards and provisions to maintain necessary safety standards while eliminating unnecessary obstacles and preventing barriers. The Consumer Advocate also noted that the Board had expressed its intent to monitor interconnection issues and consider steps to modify or extend the application of its rules to non-rate-regulated utilities as necessary. This inquiry proceeding presents an appropriate opportunity to make these considerations.

The IAEC states that the Board has already extended the interconnection rules to the RECs. See 199 IAC 15.10. The Board chose to apply chapter 45 to rate-regulated utilities. Many of the RECs have modified their tariffs to be consistent with the 199 IAC chapter 45 rules; however, the IAEC does not believe the Board should mandate compliance. Some provisions in chapter 45 could be viewed as interfering with the non-rate-regulated utilities' ability to establish their own PURPA implementation plan.

The IAMU does not believe that the Board has jurisdiction to extend interconnection rules to municipal utilities. The Board only has jurisdiction over municipal utilities that is listed in section 476.1B or otherwise provided by statute. If the Board wants to require municipal utilities to adopt particular interconnection procedures and standards, it would have to be accomplished through state legislation. MRES believes there is no reason or need for the Board to extend its interconnection rules to include municipal utilities.

Staff Comments

Staff agrees with the Consumer Advocate in that extending the interconnection rules to municipal utilities and RECs would ensure common interconnection standards and provisions to maintain necessary safety standards. Staff believes that state-wide uniformity for interconnection standards is important. This allows for a uniform understanding of interconnection procedures. Staff is encouraged that several electric cooperatives and municipal utilities follow the procedures set forth in the rules. Various commenters urged that the rules also be applied to non-rate-regulated cooperative and municipal utilities. The jurisdictional issue is not well-settled and there are legitimate legal arguments on both sides. Because there continues to be a movement towards voluntary use of the interconnection rules by cooperatives and municipal utilities, staff recommends that the Board not seek to assert jurisdiction to impose interconnections standards on non-rate-regulated utilities at this time. Staff is not aware of any complaints that have been filed by prospective DG customers against RECs or municipal utilities. However, staff recommends that the Board state that it might revisit the jurisdictional issue and seek to apply the rules to non-rate-regulated utilities if Board becomes aware of significant problems with interconnection processes with RECs and municipal utilities or if more RECs and municipal utilities chose not follow the interconnection standards on a voluntary basis.

General Interconnection Comments

ESA believes that energy storage should be an integral part of an Iowa DG plan.

Winneshiek Energy District strongly recommends Iowa move forward with enabling policy on community or shared renewable energy options. Community renewable programs should follow key guiding principles, as described in the IREC’s "Model Rules for Shared Renewable Energy

Programs."[15]

Chris Hoffman of Moxie Solar states safety benefits of renewable energy saving in health care and weather related emergency service costs have been identified by the Obama Administration. DG installation reliability is improving daily.

Recommendation for Interconnection Issues

Staff recommends the Board issue an order asking the parties to respond to the questions noted above. In addition to responding to staff's additional questions, staff recommends the Board allow participants the opportunity to respond to each other's recommendation and/or comments by filing reply comments. The responses should specify which comment, recommendation, or question's response they are responding to.

Staff recommends that the Board not require long-term commitments of DG owners that plan to sell excess generation to the utility. Detailed elements of interconnection agreements should be negotiated by interconnecting parties.

Staff also recommends that the Board not seek to assert jurisdiction to impose interconnection standards on non-rate-regulated utilities at this time. However, staff recommends that the Board state that it might revisit the jurisdictional issue and seek to apply the rules to non-rate-regulated utilities if significant problems develop or if more RECs and municipal utilities do not follow the interconnection standards on a voluntary basis.

INTERCONNECTION RECOMMENDATION APPROVED

IOWA UTILITIES BOARD

The Board should also state that it encourages RECs & Munis to follow the lead of some of their peers who voluntarily follow the interconnection standard.
/bkb

/s/ Elizabeth S. Jacobs *9-8-14*
Date

/s/ Nick Wagner *9/9/14*
Date

See my additional questions/comments attached.

/s/ Sheila K. Tipton *9/10/2014*
Date

[15] Available at http://www.irecusa.org/publications/ under the "regulatory" heading.

<u>Customer Awareness/Protection</u> (Brenda and Jamie)

The Board posed several questions to gauge the need for DG-related education, awareness, and protection for customers. Fewer participants responded to these questions compared to the net metering and interconnection questions.

1. Is there a need to educate customers about DG issues such as economics, tax incentives, utility requirements, reputable installers, and similar considerations? If so, whose role is it and what type of education should be provided?

Generally, participants believe that the utility has the primary role for educating the customer as well as the dealer or installer of the DG system. However, some suggest that the Board and/or the Iowa Energy Center should also provide education or be a resource for customers.

IPL, MidAmerican, the IAEC, the Consumer Advocate, the IAMU, ELPC et al., and MRES agree that customers should be educated about DG. IPL and MidAmerican currently furnish DG information on their web sites. The IAEC, the IAMU, and MRES also state that the Iowa Energy Center is a good resource for customers. ELPC et al. encourage the Board to ensure that education is transparent with respect to the benefits and costs of DG, and customers need to have access to information on reputable dealers, utility requirements, and other considerations for DG. MRES suggests the Board set up a web site containing tax incentive information, basic interconnection requirements, notices regarding disreputable installers, and scams that municipal utilities can direct customers to. The site should also provide information to customers on how to report a scam and how to seek retribution and damages if they have been subject to a scam. The Sierra Club – Iowa Chapter believes the Board is in the best position to provide objective educational DG information to customers while All Points Power and Industrial Energy Applications believe customer education should be left to market participants.

Decorah Solar Field, Frank Belcastro, John E. Carpenter, Jason Hall, Jean Marie Hall, Jenn Hall, Kami Ahrens, Larry Stone, John B. Cook, and Moxie Solar agree that there is a need for education about DG issues such as; economics, tax incentives, utility requirements, and reputable installers. This education could come from the utilities and installers. Energy Consultants Group suggests the utilities are responsible for educating customers with educational resources easily accessible on the utility web sites. Wendy VanDeWaller mentions that the public needs to be more informed about DG so that they feel enabled to use appropriate installation resources.

Staff Comments

The Board's current Web site does not contain specific information or links to DG rules and processes. Staff recommends the Board consider developing a webpage and/or brochure which would provide general DG information and provide links to utility information and additional resources such as the Iowa Energy Center. Once the content is developed, the utilities and other organizations could link to the information or webpage.

2. Should the Board develop a checklist to assist customers in understanding the process and responsibilities associated with installing DG or does one already exist? What issues should consumers consider when installing DG (both renewable and nonrenewable)?

Nearly all participants responding to this question believe that developing a standard checklist for customers would be a useful tool but suggested different parties to be responsible for developing the checklist. Several suggest existing checklists that could be used as a starting point while others provided items that should be included on a checklist.

IPL, MidAmerican, the IAEC, and the Sierra Club – Iowa Chapter provided checklists currently used for customers interested in DG. IPL suggests the checklist should be developed and widely available via the utility, Iowa Energy Center, Board, and the Consumer Advocate web sites. The IAMU and MidAmerican specifically mention that the Iowa Energy Center is a good source of information, and the IAMU suggests the Iowa Energy Center should develop a checklist with referral to the local utility.

Energy Consultants Group states that the Board should develop a simple checklist, but notes it will only be effective if a standard system is adopted. Energy Consultants Group also refers to a checklist developed by the North American Board of Certified Energy Practitioners (NABCEP).

MRES encourages the Board, the Consumer Advocate, or Iowa Energy Center to establish a DG checklist but also suggests that customers be directed to meet with their utility to discuss potential issues unique to the municipal utility. Communication of compliance with laws, safety standards, and operational mandates are important subjects to be considered for the checklist. ELPC et al. note the Board should be mindful and wary of community rules or civic ordinances restricting the development of solar in Iowa.

Decorah Solar Field, Frank Belcastro, Jason Hall, Jean Marie Hall, Jenn Hall, Kami Ahrens, Larry Stone, Moxie Solar, John B. Cook, and Luther College agree that the Board should develop a checklist to assist customers in understanding the process.

The Consumer Advocate states that MidAmerican and IPL were directed to offer information (which could be a checklist) to help guide customers in assessing the feasibility of DG in recent energy efficiency dockets. The Consumer Advocate also mentions that the Board may want to reference a checklist to help guide interested customers toward the extensive information available through the investor-owned utilities' (IOU) education, outreach, and training efforts.

All Points Power and Industrial Energy Applications think that developing a check list would be better served by market participants with the Board limiting its role to that of an enabler.

Staff Comments
Staff recommends the Board convene a workshop to allow participants an opportunity to help develop a standard checklist. To begin a discussion, staff has drafted a checklist (See Appendix B) which incorporates many of the participants' suggestions. Staff suggests the Board post the final checklist on the Board's Web site and distribute it to various parties to be posted on their web sites or used as an educational tool for DG.

3. With respect to public safety, who is primarily responsible for the issue of fire safety and fire suppression activities, the customer or local fire officials?

a. Should customers be required to provide local fire officials information regarding their solar installations?

b. Should fire officials be required or encouraged to maintain detailed logs regarding solar installations in their community or fire district?

Respondents thought that the State Fire Marshal Division of the Iowa Department of Public Safety and local fire officials are responsible for public safety. None of the participants suggest the Board be involved in this issue. Furthermore, participants recommend that the owners of DG facilities or the interconnected utility notify local officials of solar installations.

The Consumer Advocate, the IAEC, the IAMU, ESA, All Points Power, Energy Consultants Group, and Industrial Energy Applications agree that local fire officials and the State Fire Marshal's office are responsible for these issues. MidAmerican, Moxie Solar, Industrial Energy Applications, Jason Hall, Jean Marie Hall, Jenn Hall, Kami Ahrens, and Larry Stone mention that DG owners should provide fire officials with information regarding their solar installations while Luther College suggests that utilities forward all DG interconnection agreements to local fire officials.

MidAmerican, MRES, and ELPC et al. note that concerns with solar DG in firefighting activities are addressed in the 2012 International Fire Code. The

Iowa Fire Marshal and most Iowa cities have adopted the 2009 International Fire Code but not the 2012 version. IPL suggests that the report "Fire Fighter Safety and Emergency Response for Solar Power Systems," offers best practice guidance for emergency response.

According to William J. Pardee and John E. Carpenter, there are not any special fire risks associated with properly installed solar systems. Mr. Pardee does not believe that customers should be required to provide local fire officials information regarding solar installations nor should fire officials be required to keep logs of solar installations.

Staff Comments

Staff recommends the Board rely on the State Fire Marshal Division of the Iowa Department of Public Safety to determine whether additional measures need to be implemented to ensure that DG does not hamper or jeopardize fire personnel. Additionally, staff recommends contact information for the State Fire Marshal Division of the Iowa Department of Public Safety be included on the DG checklist, webpage, or other information developed regarding DG installations.

4. Do current Iowa consumer protection laws adequately address the responsibilities of the DG suppliers/distributors? Who should be responsible for resolving consumer complaints regarding DG suppliers/distributors (Iowa Utilities Board, the Attorney General's office, or some other agency)?

In general, most participants assert that the Attorney General's (AG) office is responsible for determining the adequacy of the consumer protection laws and should be responsible for resolving DG-related consumer complaints. Several individuals say that the Board should have jurisdiction to resolve customer complaints. One respondent suggests that the Board should handle complaints related to tariffs and interconnection and the AG should handle those that are commercial in nature.

IPL, MidAmerican, the Consumer Advocate, the IAEC, ELPC et al., All Points Power, and Industrial Energy Applications agree the AG's office is responsible for determining the adequacy of current Iowa consumer protection laws and should be responsible for resolving consumer complaints regarding DG suppliers/distributers.

Energy Consultants Group states that the Board is not the best entity to protect consumers, given the long relationship with utility companies and suggests that an agency not tied with the state or utility companies would be ideal to resolve consumer complaints.

Jason Hall, Jean Marie Hall, Jenn Hall, Kami Ahrens, Larry Stone, and Moxie Solar say that the Board should have jurisdiction to resolve any consumer complaints.

Staff Comments

Staff recommends the Board defer to the AG's office to handle DG-related consumer complaints – unless the complaint is related to utility tariffs or interconnection issues. Staff also recommends contact information for the AG's office be included on the DG checklist, web page or other information developed regarding DG installations.

5. Should DG suppliers/distributors be required to be certified as qualified to supply/install the equipment/project in question? Who should perform the certification? Who, if anyone, should maintain a listing of certified DG contractors/installers?

Many of the participants responding to this question support the requirement for installers to be certified; however, the parties do not agree as to who should certify or maintain a list of those certified. Several respondents do not think certification is necessary.

ELPC et al. say that existing rules already provide sufficient consumer protection. All Points Power states that the issue of licensing suppliers and vendors may be a good marketing ploy but it is not required to ensure safe and reliable installation of DG systems. Industrial Energy Applications suggests that additional bureaucracy in the form of licensing/certification is not needed and that a supplier or installer is incented to do a good job of installation by future word-of-mouth advertising that they will receive (good or bad).

MRES, ESA, and Willam J. Pardee support certification of DG installers. Jason Hall, Jean Marie Hall, Jenn Hall, Kami Ahrens, Larry Stone, and Moxie Solar encourage certification of installers that is done by Iowa-based community and technical colleges. John E. Carpenter recommends that DG installers be certified in the same manner as electricians; however, DG designers and installers should not need to be licensed electricians. IPL, ELPC et al., Energy Consultants Group, and the Sierra Club – Iowa Chapter agree that if the Board decides to require certification, it should rely on the certification from the NABCEP or another national established certification program. The Consumer Advocate suggests a quality assurance type process could be part of the renewable energy education, outreach, and training provided by Iowa's IOUs.

MidAmerican states that if DG is to be a substitute for utility generation, then it is appropriate to regulate all aspects of this supply and then referenced a certification process that was implemented in Illinois as of January 1, 2014. The

IAEC suggests the Board develop a certification process like that currently used for the certified natural gas providers in 199 IAC 19.14.

Jason Hall, Jean Marie Hall, Jenn Hall, Kami Ahrens, John E. Carpenter, Larry Stone, Moxie Solar, and John B. Cook concur the Board should keep a list of certified DG contractors. The IAMU suggests an unbiased third party maintain a list of those certified.

Staff Comments

During the 2006-2007 legislative session, legislation was enacted that required all electricians and electrical contractors to be licensed by the State Fire Marshal Division of Iowa Department of Public Safety. Staff believes that this agency is better suited to determine whether licensing or certifying DG installers is necessary. However, staff believes that it is important for customers to be aware that there are entities that certify DG installers. As part of the education and checklist, staff recommends including information about the importance of certification and also a link to the NABCEP webpage for customers interested in checking to see if a particular installer is certified.

Recommendation for Customer Awareness/Protection Issues

Staff recommends the Board develop a webpage and/or brochure which would provide general DG information and provide links to utility information and additional resources such as the Iowa Energy Center.

Staff also recommends the Board convene a workshop to allow participants an opportunity to help develop a checklist. The draft checklist in Appendix B should be attached to the order to allow participants an opportunity to review the information prior to the workshop.

Staff recommends the Board rely on the State Fire Marshal Division of the Iowa Department of Public Safety to determine whether additional measures need to be implemented to ensure that DG does not hamper or jeopardize fire personnel and to determine whether DG installers should be licensed or certified. Additionally, staff recommends contact information for the State Fire Marshal Division of the Iowa Department of Public Safety is included on the DG checklist, webpage, or other information developed regarding DG installations. Staff also suggests that the checklist include a link to the NABCEP webpage.

Staff recommends the Board defer to the Attorney General's office to handle DG-related consumer complaints – unless the complaint is related to utility tariffs or interconnection issues. Staff also recommends contact information for the Attorney General's office be included on the DG checklist, webpage or other information developed regarding DG installations.

CUSTOMER AWARENESS/PROTECTION RECOMMENDATION APPROVED

IOWA UTILITIES BOARD

/s/ Elizabeth S. Jacobs *9-8-14*
Date

/bkb

/s/ Nick Wagner *9/9/14*
Date

/s/ Sheila K. Tipton *9/10/2014*
Date

<u>General Questions</u> (Barb, Parveen, and Brenda)

1. For calendar year 2013, provide the following detailed information (in an Excel file) related to each DG facility connected to your utility system:

IPL, MidAmerican, the IAEC, and the IAMU filed data in response to this question which staff compiled into a single Excel file. Information from the combined data is presented in several tables below.

<u>Staff Comments</u>
Staff combined the raw data provided by the utilities into a single spreadsheet. There are questions that need to be clarified in order to be sure that the combined data is as accurate as possible. The following information is based on staff's current understanding of the combined data.

The total capacity of the DG interconnections in Iowa is 1,019,606 kW or 1,020 MW. Of this, 97 percent is interconnected with IOUs, 2 percent with RECs, and 1 percent with municipal utilities. Out of this total, 20 MW are net metered. Additionally, based on the data provided, for IPL and MidAmerican only, it appears that hourly load data is available for the DG capacity associated with all residential customers. For MidAmerican, hourly load data is available for 10 percent of the non-residential DG capacity and for 59 percent of IPL's non-residential DG capacity.[16]

Table 1 shows the MW and percentage breakdown of DG in Iowa by fuel category.

Table 1	**MW by Utility Type & Fuel Type**			
	IOU	**REC**	**Muni**	**Total**
Wind	334	12	13	358
Solar	5	2	0	7
Diesel	35	-	-	35
Hydro	8	-	-	8
Methane	10	5	-	16
Natural Gas	3	-	-	3
Coal / CHP	440	-	-	440
Biomass	2	-	-	2
Coal & Nat Gas / CHP	80	-	-	80
Non-Bio Diesel	18	-	-	18
Natural Gas, Coal, Other	43	-	-	43
Coal	10	-	-	10
Total	**987**	**19**	**13**	**1,020**

[16] Non-residential includes what may be large cogeneration units.

Table 2 shows the MW and percentage breakdown of DG capacity by utility type and transaction type.

Table 2	MW by Utility Type & Transaction			
	IOU	REC	Muni	Total
Net Metered	16	3	1	20
Offset & Sale to Utility	183	-	-	183
Offset Only	353	-	-	353
Sale to Utility	335	-	-	335
Standby	2	-	-	2
Not Classified by the Utilities	99	16	12	127
Total	**987**	**19**	**13**	**1,019**

Table 3 shows DG implementation year-by-year for each utility type and fuel category.

Table 3	Year-to-Year MW by Utility Type & Fuel Tpe													
1,019.60	333.56	5.45	34.53	8.22	10.25	1.80	520.00	17.94	55.65	11.64	1.75	5.43	13.16	0.22
100.00%	32.71%	0.53%	3.39%	0.81%	1.01%	0.18%	51.00%	1.76%	5.46%	1.14%	0.17%	0.53%	1.29%	0.02%
	IOU	IOU	IOU	IOU	IOU	IOU	IOU	IOU	IOU	REC	REC	REC	Muni	Muni
Muni	Wind	Solar	Diesel	Hydro	Methane	Biomass	Coal and/or Nat Gas / CHP	Non-Bio Diesel	Natural Gas, Coal, Other	Wind	Solar	Methane	Wind	Solar
1954	-	-	-	0.0003	-	-	-	-	-	-	-	-	-	-
1970	-	-	-	-	-	-	-	-	43.25	-	-	-	-	-
1975	-	-	-	-	-	-	-	-	9.60	-	-	-	-	-
1981	-	-	-	-	-	-	-	-	-	0.01	-	-	-	-
1985	0.01	-	-	-	-	-	-	-	-	-	-	-	-	-
1988	-	-	-	-	-	-	260.00	-	-	-	-	-	-	-
1989	-	-	-	3.25	-	-	-	-	-	-	-	-	-	-
1991	-	-	-	-	-	0.29	-	-	-	-	-	-	-	-
1992	-	-	-	-	6.40	-	-	-	-	0.08	-	-	-	-
1993	0.45	-	-	-	-	-	-	-	-	-	-	-	-	-
1995	0.51	-	-	-	3.85	-	-	-	-	0.03	-	-	-	-
1996	0.26	-	-	-	-	-	-	-	-	0.07	-	-	-	-
1997	79.97	-	-	1.00	-	0.45	-	-	-	-	-	-	-	-
1998	0.00	-	1.20	0.40	-	-	-	-	-	-	-	-	-	-
1999	-	-	-	-	-	-	-	-	-	0.03	-	0.03	1.20	-
2001	80.85	-	-	-	-	-	-	-	-	0.12	0.00	-	-	0.02
2002	0.25	-	18.58	-	-	-	-	-	-	0.01	0.02	-	-	0.00
2003	43.52	-	4.76	-	-	-	-	-	-	0.01	-	-	-	-
2004	1.55	-	-	-	-	-	80.00	3.00	-	0.57	0.01	-	1.35	-
2005	1.56	0.01	1.00	2.69	-	0.06	-	-	-	0.11	0.00	-	-	-
2006	0.01	0.01	5.00	-	-	-	-	-	-	0.13	0.01	4.80	-	-
2007	14.86	0.00	4.00	-	-	-	-	-	-	0.03	0.01	-	-	0.01
2008	80.94	0.02	-	-	0.00	-	-	-	-	0.01	-	-	0.00	-
2009	0.79	0.10	-	-	-	-	180.00	3.94	2.80	1.27	0.03	-	0.00	0.00
2010	0.93	0.06	-	-	-	-	-	2.00	-	4.54	0.06	-	-	0.02
2011	5.72	0.36	-	0.88	-	-	-	-	-	2.51	0.21	-	5.53	0.04
2012	21.13	1.31	-	-	-	-	-	6.00	-	1.99	0.21	0.60	4.97	0.04
2013	0.25	3.59	-	-	-	1.00	-	3.00	-	0.08	1.08	-	-	0.08
2014	-	-	-	-	-	-	-	-	-	0.06	0.12	-	0.10	0.01
Not Reported	-	-	-	-	-	-	-	-	-	-	-	-	-	0.01

The consolidated data provide an overview of rate and type of DG deployment over the years in Iowa. The table below (which appears on the Board's Web site) shows the 2012 generation capacity information which is the most current information available from EIA.

Electric Generation in Iowa by Primary Energy Source	2012 Nameplate Capacity (MW)	Percent
Coal	7,215.90	41.78%
Wind	5,103.90	29.55%
Natural Gas	2,936.10	17.00%
Fuel Oil / Petroleum	1,189.70	6.89%
Nuclear	679.5	3.93%
Hydro	131.3	0.76%
Other Renewables	14.6	0.08%
Total	**17,271.00**	**100.00%**

The consolidated data shows that 64 of the 1167 DG facilities have a capacity of 1 MW or greater and that these facilities account for 991 MW, or 97 percent of the total reported DG capacity. Staff is uncertain whether any of the DG reported by the utilities in this docket is also reported to EIA and is, therefore, included in the 17,271 MW total generating capacity reported by EIA for Iowa. Assuming the 1,104 facilities which are less than 1 MW have not been included in the EIA data[17], their capacity (29 MW) would bring Iowa's total electric generating capacity to 17,300 with DG (as reported in this docket) accounting for nearly 6 percent of that total.

The labels used by each of the participants that provided data were not entirely consistent. In order to analyze the data, staff applied uniform labels across the data. As a means of ensuring the accuracy of the compiled data, staff suggests providing the consolidated data file to the participants so they can review the data and confirm its accuracy. Additionally, IPL provided data for CHP facilities. In order to confirm that the data are comparable across all sources, staff recommends the following specific questions in order to further clarify the Iowa DG profile and its accuracy.

1. For each reported DG facility, indicate whether capacity and/or generation data for that facility is reported to EIA. In other words, do the DG facilities file either EIA 860 or EIA 923 reports? If so, identify those facilities.

2. Did you include all CHP installations in the data you provided? If not, provide comparable data for all CHP installations in your service territories.

3. Based on the data provided, it appears that hourly load data is available for the DG capacity associated with all residential customers for both IPL and MidAmerican; for 10 percent of the non-residential DG

[17] Typically facilities that are less than 1 MW are not required to report generation data to EIA.

capacity for MidAmerican; and for 59 percent of IPL's non-residential DG capacity.

For MidAmerican and IPL:

a. Is the above statement accurate? If no, what are the correct percentages?
b. If yes, discuss what would be required in order to get hourly data for the remaining DG capacity?

2. Should Iowa have a policy goal to increase and diversify alternate energy production? If so, should that policy be achieved with utility-owned centralized generation, utility-owned distributed generation, customer-owned distributed generation or a mix of these alternatives? Discuss the advantages and disadvantages of these approaches.

IPL, MidAmerican, and the Consumer Advocate believe Iowa has a policy goal to increase alternate energy production. The IAEC says that given the legislative policies, there is no need for the Board to enter into this business. The IAMU believes utilities should set their own goals. MRES believes the Board should work with utilities to determine what works best. ELPC et al. state that Iowa has a clear statutory policy goal to increase and diversify alternate energy production.[18] The Board should look at policies that encourage a range of options for building alternative energy.

Ben Grimstad, John E. Carpenter, and John B. Cook support policies that promote DG while TASC supports customer-owned DG. Larry A. Stone states Iowa should have a policy goal to increase and diversify alternate energy production. Sierra Club - Iowa Chapter, Decorah Solar Field, Frank Belcastro, Jason Hall, Jean Marie Hall, Jenn Hall, Kami Ahrens, Moxie Solar, William H. Ibanez, Industrial Energy Applications, and All Points Power support a policy to increase DG and believe customer-owned generation is the most beneficial.

EcoWise Power believes Iowa needs a statewide, consistent policy which includes RECs and municipal utility customers whereas Robert Fischer recommends the Board should set a goal for increasing the generation of clean and renewable energy wherever possible and encourage DG and virtual net metering. Likewise, Luther College Wind Energy Project LLC believes the Board could further support Iowa’s current goal by expanding the current net metering policy and by requiring utilities to offer FITs. ESA recommends policies should encourage both utility and third-party ownership models for energy storage. Luther College believes Iowa does not need a policy goal to increase and

[18] Iowa Code § 476.41

diversify alternate energy production but that Iowa should strive for a mix of utility and customer-owned DG systems.

The Iowa Chapter – Physicians for Social Responsibility and William J. Pardee believe the Board has the responsibility to protect all Iowans and society. Distributed energy encourages investment in renewable energy and reduces the harms associated with fossil fuels. The Board should improve and expand on what others have already put in place rather than create a new policy.

Staff Comments

Utilities believe that the Iowa legislature has already set a policy goal for alternate energy production. Most commenters support policies that further DG. One commenter suggests that the state adopt policies that advocate specific DG technology. Most commenters prefer customer-owned DG over utility-owned. Several commenters acknowledged that Iowa has policies that promote alternative energy production.

Staff believes that, at this time, it is not necessary for the Board to adopt additional policy goals that encourage DG deployment. The state of Iowa has a policy that promotes alternative energy production, and the Board has already adopted rules (IAC-199 chapter 45) that provide DG interconnection policies and processes. When adopted in 2010, under Docket No. RMU-2009-0008, Iowa's rules were considered by all parties as thoughtful and comprehensive. More issues related to DG promotion are discussed in the customer protection section of this memo.

3. What are the current incentives, if any, for the utility to promote DG and for the customer to own DG? Should alignment of DG production with utility peak demand be the target of an incentive?

IPL believes utility incentives today are in the form of market development or understanding and good will. Net metering may fit the definition of customer incentives. IPL prefers a pricing system which places all forms of generation on a level playing field. Aligning incentives (payments) with a utility peak should be based upon the value the utility receives from its regional transmission operator or power pool for that generation. If small DG is not eligible for a resource credit from the regional transmission operator there may not be an incentive for only an energy credit.

MidAmerican states the current DG rate structure and net metering policies discourage and create barriers to promote and integrate DG into the grid. Customer and utility collaboration in projects such as local solar installations owned, operated, and maintained by MidAmerican would allow for optimal location and maximum resource mix while minimizing adverse reliability and safety impacts. In the proper rate structure, DG customers may conclude that it is in their best economic interests to optimize peak demand and energy production in total.

The Consumer Advocate believes the current incentive for the utility to promote DG is that DG can help the utility optimize its resource portfolio. Current incentives for a customer to own DG are primarily financial in that DG allows a customer to benefit from reduced energy consumption from the utility. Incentives should not be based solely on DG production during peak periods. Incentives should be based on the value a resource can be expected to provide a utility based on its generation characteristics.

The IAEC states circumstances determine whether DG investment is beneficial or whether there are stranded or increased costs. It is preferred that incentives provided by the governments match demand and supply.

The IAMU and MRES believe each municipal utility evaluates incentives based on local conditions. The IAMU further states that community solar development would benefit from shared solar tax credits made available to municipal utilities.

ELPC et al. note that currently there is a mix of state and federal incentives. ELPC et al. suggest that a comprehensive DG study will identify and quantify these benefits and costs and allow for value of incentives to be maximized. Aligning DG production with utility peak demand is one of these values and should be considered in the context of all values rather than alone. The Sierra Club - Iowa Chapter agrees that alignment of DG production with utility peak demand should be the target for incentives.

Decorah Solar Field, Frank Belcastro, Jason Hall, Jean Marie Hall, Jenn Hall, Kami Ahrens, Moxie Solar, and William H. Ibanez comment that currently there are no incentives for utilities to promote DG. Federal and state tax incentives for solar projects in Iowa and United States Department of Agriculture Rural Energy for America Program (REAP) grants, for farmers and small rural businesses, combined with net metering provide a system payback of ten years or less.

According to All Points Power and Industrial Energy Applications, current incentives for customers include tax incentives for renewable generation but are more limited for CHP/WHP, peak shaving, interruptible power, etc.

John E. Carpenter believes the utility has very little incentive to promote customer-owned DG but acknowledges there may be some incentive if utilities could negotiate aggregation of renewable energy credits with its customers. Energy Consultants Group and Wendy VanDeWalle believe all utilities should offer rebates as incentives for DG.

Luther College believes solar PV and natural gas-fired CHP systems can contribute to peak power production and should be incentivized. Utilities should also provide incentives for energy storage systems when they become cost effective and commercially available.

John B. Cook believes the Environmental Protection Agency's (EPA) emission reduction plan is a significant incentive for utilities to increase alternate energy production and DG is one way to do that. DG can help REC's mission to serve their member/customers. Incentives for customer ownership include tax credits, favorable return on investment, and a desire to slow global warming.

William J. Pardee states customers install solar and wind to reduce the negative costs associated with fossil fuel extraction and as an effort to stabilize future energy costs. With the task of reducing emissions, utility business model is failing, and they need help to find a new role. It seems fair to use time of day metering and pricing with net metering to align utility peak demand with DG, though the DG system has little real control over time of production.

Staff Comments
MidAmerican believes there are no incentives for the utility to promote DG, while the Consumer Advocate believes DG contribution to a utility's resource mix is an incentive. IPL calls net metering an incentive while MidAmerican classifies net metering as a barrier. Most non-utility commenters would like utilities to give incentives to DG customers. Recommended incentives ranged from tax incentives to direct cash rebates. One commenter stated that if washing machines can have rebates, why can't DG. All commenters recognize that DG contributes towards both peak demand and energy load profiles. The commenters did not provide comments that would result in a consensus position on the issue of incentives.

4. Do utilities include distributed generation in their resource planning? If so, how is DG accounted for? If not, why and is this likely to change?

The amount of DG on IPL's system is relatively small. In the near term, the expected amounts of DG are not likely to be great enough to justify an explicit forecast of DG applications. Sensitivity testing of the plans with lower load forecasts would be reflective of greater amounts of DG, amongst other factors.

MidAmerican includes DG in capacity credit planning to the extent such resources can be registered with MISO. DG assets registered with MISO for capacity credits as a Load Modifying Resource would need to have an obligation to be made available during emergencies. While MidAmerican has some behind the meter generation that meets these requirements, this would likely not be the case for small DG installations. Peak demand and energy forecasts for load are net of DG not registered with MISO. Historical load data include energy production from non-registered DG. New forecasting methods to include DG as a separate forecast may be required if there are significant increases in the amount of DG.

The Consumer Advocate states that in the recent avoided cost workshops in Docket No. INU-2014-0001, MidAmerican and IPL described modeling DG as a net load impact in its IRP process by subtracting it from a gross load growth projection. At the same time, many utilities are considering DG to be modeled as a generation resource option, rather than a net load impact.

The IAEC states that to the extent historical load data are used to develop load forecasts, the existence of DG impacts resource planning. The IAMU and MRES state that municipal utilities and joint action agencies are evaluating best practices for integrating DG into their resource options.

TASC is unaware of utilities including customer-owned DG in their resource planning. TASC believes that utilities need to start accounting for the likely sources of customer-sited generation and load in their plans.

ELPC et al. state that currently, MidAmerican and IPL do not include DG or energy efficiency as resources in their plan and, instead, reflect them in their load forecast undervaluing DG resources in a variety of areas such as avoided cost calculations and integrated resource planning. This docket should look at how Iowa utilities can take steps to treat DG as a resource and appropriately incorporate DG into their integrated resource planning. This requires thinking about a number of issues that Iowa has the opportunity to work through in a thoughtful way before significant amounts of DG are on the grid, and the Board should take advantage of this opportunity.

ESA states that as Iowa utilities develop future plans energy storage technologies and applications should be one of the options. The operational data from demonstrated energy storage projects should allow for a greater level of comfort as utilities integrate energy storage into the daily operation of their systems. As states begin to determine how best to meet greenhouse gas emission targets, energy storage will become a critical tool. Ensuring diversity of the resource mix in this transition will necessitate fully leveraging the range of benefits energy storage can supply.

Staff Comments

Iowa utilities currently model DG as an impact on load growth. MISO continues to look into options to model DG as a resource that is available during emergencies. Staff believes modeling of DG as a resource will depend on DG technology improvements, implementation and penetration of that technology, and continued efforts to improve sophistication of resource planning models. The utility industry is aware of this issue, and integration of DG resources in everyday utility operations is being studied at various levels.

Staff is aware that if a DG facility, such as a solar installation, is modeled as a resource in traditional IRP modeling, it is unlikely that such a resource will be chosen as a viable option due to its size and costs. Also, MISO is working on defining assumptions for modeling DG in future transmission expansion studies. Staff will continue to monitor the progress being made at the regional and national levels.

5. What is the rate of DG adoption currently experienced by each utility and what is the rate projected to be in the next five to ten years? Do these adoption rates cause problems with transmission and distribution planning? How do utilities cope with this challenge?

IPL is not able to project at what rate the penetration will continue as the historical adoption rate has been influenced by IPL's Efficiency First Renewable Rebates pilot. Future DG adoption will likely be influenced by the continuation of declining equipment costs and the availability of tax incentives and the REAP grant. IPL is working with ITC Midwest and MISO on procedures to ensure DG is not impacting the operation of the transmission system. From a distribution planning perspective, entire feeder voltage and load support based on century-old electric design needs to be re-evaluated.

MidAmerican has 156 DG facilities on the system with 139 under the net meter tariff. While interest in solar rooftop facilities has increased over the last few years, MidAmerican does not have projections nor has it determined a level where transmission and distribution planning issues may appear. Now is the time to address DG issues before penetration levels cause potential reliability and system planning issues and before cross-subsidization issues create significant rate increases for customers who do not have DG facilities. DG is just one of the many issues utilities deal with on a day-to-day basis as they plan and operate the electric system and deliver energy supply to their customers.

The IAEC states that due to the numerous variables, the RECs have not made formal projections on adoption rates. Load forecasts, to a certain extent, take into account adoption rates for DG. The IAMU states the rate of DG adoption is low among municipal utilities. Municipal utilities are working with the IAMU and their Joint Action Agencies to develop tools needed to optimize DG installation such as a checklist of distribution system impacts and mitigation for DG adoption. The Board and the Organization of MISO States may wish to initiate discussion with MISO and transmission owners to determine the impact of significant DG on the costs and benefits of high voltage transmission investments. As DG becomes more prevalent, municipal utility leaders will need to develop a new business model that recognizes the value, compensation, and costs of DG.

MRES states the rate of adoption of DG within MRES Iowa member communities is low and unpredictable. The future rate of adoption may be positively impacted as more members implement the DG interconnection workbook of MRES or that of the IAMU.

The Consumer Advocate states utilities are in the best position to provide this information, while ELPC et al. state it is difficult to track the DG market and adoption rate in Iowa on a statewide basis due to the numerous utilities in Iowa. ELPC et al. believe the adoption rate for DG technologies like solar PV in Iowa is currently slower than most states and significantly slower than leading states. Evidence suggests that problems occur only at very high deployment levels and should, thus, not be an issue in Iowa now or in the foreseeable future. In order to project a DG adoption rate for Iowa, a study could be conducted that takes into account (a) the existing policies, (b) electricity prices, (c) empirical evidence from similarly situated jurisdictions, and (d) future expectations for policies. Although this study could be difficult, a general idea of a future adoption curve for DG could then be used in transmission and distribution planning.

Staff Comments

None of the commenters provided projections for DG penetration and almost all stated that the adoption rate is low in Iowa. ELPC et al. suggested a study could be done to project DG adoption, but also point out such a study would be difficult to conduct. The responses to this question tie closely with responses to the first question which asked utilities to provide information on actual DG interconnections. Please refer to the staff analysis provided for Question 1.

<u>Recommendation for General Issues</u>

Staff recommends the Board continue work with utilities to ensure the DG data gathered are as complete as possible to be useful in evaluating the penetration of DG in Iowa. Staff recommends the Board ask the specific questions listed above to further clarify the Iowa DG profile and its accuracy. Staff also suggests the Board schedule a conference call with the utilities, utility organizations, and other interested participants to discuss and clarify the DG data.

Additionally, staff recommends the Board encourage participants to respond to the following question regarding the impact of the recent Supreme Court decision.

4. On July 11, 2014, the Iowa Supreme Court issued its opinion in No. 13-0642, SZ Enterprises, LLC d/b/a Eagle Point Solar v. Iowa Utilities Board, a Division of the Department of Commerce, State of Iowa, et al. What are the legal impacts, if any, of this decision on DG policies or practices in general and particular policies or practices such as net metering (both traditional and virtual)? Does the decision impact any of your prior comments or responses in this docket? If so, explain.

GENERAL ISSUES
RECOMMENDATION APPROVED

IOWA UTILITIES BOARD

/s/ Elizabeth S. Jacobs *9-8-14*
Date

/bkb

/s/ Nick Wagner *9/9/14*
Date

/s/ Sheila K. Tipton *9/10/2014*
Date

Additional questions (or clarification to the questions) for NOI-2014-0001

Under the Net Metering section:

Virtual Net Metering

1. *The IAMU notes that at least one municipal utility offers virtual metering. How is this being done (given the legal concerns expressed by some commenters)?*

Meter Aggregation

1. *INEDA points to MN, IL, AR, and CO meter aggregation rules for Board consideration. Could any of these approaches be appropriate for Iowa?*

Under the Interconnection section:

12. In addition to seeking comments on IPL's proposal to increase the Level 1 and Level 2 application fees to $250, ask for justification of keeping fees the same or raising them to the IPL recommended level.

9-8-14

Libby Jacobs

Additional Questions for NOI-2014-0001

Net Metering:

1. *Please provide comments on MEC's assertion that a cash out encourages overbuild of a DG system.*

Interconnection:

2. *There are several commenters that point to the benefits of DG and there are questions about the benefits. Is there additional harm or burdens placed on the system by DG and if so what are they?*
3. *Does IPL have a cost study to show the true interconnection costs exceed the current fees?*
4. *MEC has indicated that a DG owner is a different type of customer and should be treated as a separate class. Please provide comments on how this should be done, if it should be done, or if there is a different way to account for differences between customers.*

9/9/2014

Nick Wagner

Additional Questions for NOI-2014-0001

NET METERING:

1. I propose that the following question be insert following as question 17(c) and that current (c) and (d) then be renumbered to (d) and (e):

"(c) If your response to part (b) of this question is that a study should be delayed until DG penetration increases, what level of penetration do you believe would justify the study?

2. I propose adding the following questions:

[#] For those municipal utilities and rural electric coops that do not currently offer net metering:

a. Please explain why you do not currently offer net metering.

b. Please state whether you intend to offer net metering and if so, when.

3. I propose that our order "strongly encourage" (as opposed to "continue to encourage") municipal utilities and RECs to follow the lead of the IOUs and begin offering net metering to their customers.

INTERCONNECTION:

1. [Insert between current Q 12 and Q 13] [To MidAmerican and Interstate Power] What number of DG customers would be required before you would be able to conduct cost of service studies to determine DG customer class rates?

2. As with Net Metering, I propose that our order "strongly encourage" municipal utilities and RECs to follow the IUBs interconnection rules on a voluntary basis and that in the absence of such voluntary action, the Board will seriously consider asserting jurisdiction to impose such a requirement on them.

September 10, 2014

Sheila K. Tipton

Appendix A – Participants Responding to the Board's May 12, 2014, Order

Utility/Regulatory

- Interstate Power and Light Company (IPL)
- MidAmerican Energy Company (MidAmerican)
- Office of Consumer Advocate (Consumer Advocate)
- Farmers Electric Cooperative – Kalona
- Iowa Association of Electric Cooperatives (IAEC)
- Iowa Association of Municipal Utilities (IAMU)
- Missouri River Energy Services (MRES)

Organizations

- The Alliance for Solar Choice (TASC)
- Environmental Law and Policy Center, Iowa Environmental Council, Sierra Club, Iowa Solar Energy Trade Association, Solar Energy Industries Association, Vote Solar Initiative and Interstate Energy Council (ELPC et al.)
- Energy Storage Association (ESA)
- Iowa Industrial Energy Group (IIEG)
- Iowa Nebraska Equipment Dealers Association (INEDA)
- Iowa Solar Energy Trade Association (ISETA)
- Midwest Cogeneration Association (MCA)
- Sierra Club - Iowa Chapter
- International Brotherhood of Electrical Workers (IBEW)

Individuals/Small Business

- Andrew Johnson – Winneshiek Energy District
- Ben Grimstad
- Birgitta Meade
- Chris Hoffman – Moxie Solar
- Craig Mosher
- Ervin D. Root, P.E. – All Points Power, LLC
- Frank Belcastro
- Gregg Heide – Farm Energy, LLC
- Jason Eglie – EPo Energy
- Jason Gideon – Energy Consultants Group, LLC
- Jason Hall
- Jean Marie Hall
- Jenn Hall
- Jim Martin-Schramm – Luther College Wind Energy Project
- Jim Martin-Schramm – Luther College
- John B. Cook
- John E. Carpenter
- Kami Ahrens
- Larry A. Stone
- Larry Grimstad - Decorah Solar Field, LLC
- Maureen McCue MD PhD – Iowa Chapter–Physicians for Social Responsibility
- Nixon Lauridsen and Rob Sand
- Norman Atwood – Atwood Electric, Inc.
- Randy Portz – Industrial Energy Applications, Inc.
- Randy Skeie – EcoWise Power
- Robert Fischer
- Steve Demuth
- Tim Brodersen – Moxie Solar
- Wend VanDeWalle
- William H. Ibanez
- William J. Pardee

Appendix B – IUB Drafted Distributed Generation Checklist

August 2014

Where to Start

- ☐ Determine the distributed generation fuel source (e.g. solar, wind, etc.).
- ☐ Learn the technology and terminology.
  Review information from the Iowa Energy Center or Department of Energy for help in understanding the economics of a distributed generation system and which type of resource is most appropriate.
  http://www.iowaenergycenter.org/renewable-energy/
  http://www.energy.gov/articles/solar-wind-hydropower-home-renewable-energy-installations

Evaluating Energy Requirements

- ☐ Determine how much energy was consumed in the past three years and the rate paid for the consumption.
- ☐ Analyze your electric loads. Evaluate peak energy and fluctuation usage time periods during the day and throughout the year.

Evaluating Energy-Efficiency Measures and Other Energy Alternatives

- ☐ Complete a thorough energy efficiency audit and implement recommendations.

Evaluating Legal, Social, and Environmental Issues

- ☐ Determine if your property is covered by restrictive covenants that affect the installation of a renewable energy system.
- ☐ Contact the local zoning board, town clerk, or building inspector to identify applicable zoning ordinances and building permit requirements.
- ☐ Discuss liability coverage and insurance needs with an insurance agent.
- ☐ To avoid unforeseen public objections to the distributed generation equipment in the neighborhood, discuss your intentions with neighbors.
- ☐ Obtain a title search to determine if prior agreements or easements exist which would prevent the distributed generation equipment from being installed on your property.

Evaluating Resources

- ☐ Determine the size of the distributed generation system that is needed to meet your energy needs and where it will be located.
- ☐ Is there enough space on the desired property to accommodate a system to work effectively (absence of trees or structures that will impact productivity)?
- ☐ Decide if your site has the potential for having sufficient renewable energy.
  - ☐ Wind calculator: http://www.iowaenergycenter.org/wind-calculator-tool/
    - Consider wind siting factors (elevation, vegetation, terrain, etc.).
    - Take wind measurements.
  - ☐ Solar Calculator: http://www.iowaenergycenter.org/solar-calculator-tool/
    - Consider solar siting factors (shading, orientation, angle, array size).

IUB Drafted Distributed Generation Checklist

Shopping for a Distributed Generation System

- Ask the following questions:
  - What safety standards must be followed and who provides oversight?
  - Who is responsible for satisfying applicable electric codes for any existing and new wiring?
  - Who is responsible for obtaining permits and authorization?
  - Who is responsible for making sure the installation meets any applicable fire department policies?
  - Who controls customer data derived from the installation?
  - What percentage of total power can the DG system be expected to provide annually?
- Review and compare options
  - Are there renewable energy program participation options available through the servicing utility?
  - Are there third party program participation options?

Dealer Considerations

(Dealers can be found on the Internet, yellow pages, and from family and friend referrals.)

- Determine the vendor's qualifications. What type of experience do they have with the specific product?
- Ask if the dealer properly licensed/certified.
  - http://www.nabcep.org/
  - http://www.dps.state.ia.us/fm/electrician/licensing/licensing_verification.shtml
- See if there any pending or active judgments or liens against the dealer?
- Ask for references from other customers, check the references. Look at other installations made by the vendor. Ask questions about the system's reliability, performance and repair needs both pre- and post-installation.
- Get estimates from multiple vendors and compare.
  - Make sure the estimates are for the same type of system.
  - The estimate should include detailed costs (including hardware, installation, connection to the grid permitting, sales tax & warranty).
- Ask if the vendor has insurance and what it covers.
- Inquire about the dealer warranty.
- The vendor should be able to help determine any special tax incentives that the system would be qualified to receive
- Determine who is responsible if there are injuries to the crew or the public during installation.
- For solar, ask the following questions:
  - What type of roof preparation is needed and what condition does the roof need to be in for a roof mount?
  - If there are structural damages other than to the roof resulting from the installation, who is responsible for repairs?
- Beware of scams: Be wary and watch out for red flags
  - Door-to-door solicitations
  - Requests for verbal agreements
  - High pressure sales tactics
  - Demands for cash
  - Scare tactics

IUB Drafted Distributed Generation Checklist

- Demands for large down payments

Equipment Considerations

- ☐ Determine the warranty associated with the specific equipment manufacturer. Ask the following questions:
  - Who is responsible for equipment replacement while the hardware is under warranty?
  - If there is a hardware warranty issue, who is responsible for the costs of removing the old panel and installing the replacement panel?
  - What are the consequences and remedies for the hardware warranty if the hardware manufacturer goes out of business?
  - If there is a warranty issue, can you coordinate repairs or do you have to let the manufacturer or installer have an opportunity to resolve the issue?
  - If there is a catastrophic event, who pays for the loss?
  - Who provides notice and what other provisions apply if the installer or inspector needs access to your home?
- ☐ For solar, ask the following:
  - Who is responsible for post-installation roof inspection?
  - Who is responsible for post-installation roof repair?
  - Who is responsible for removal and reinstallation of the system when your roof needs replaced or repaired?

On-going Maintenance Considerations

- ☐ Talk with your system installer about routine and periodic maintenance. In the event of a system malfunction, effective troubleshooting and repair is necessary.
- ☐ For rooftop solar – consider roof maintenance.

Determine the Requirements for Utility Interconnection

- ☐ Review the Board's Interconnection Rules. https://www.legis.iowa.gov/law/administrativeRules/rules?agency=199&chapter=45&pubDate=07-23-2014
- ☐ Contact city, county, and state officials for codes and regulations that must be followed for the installation and operation of a distributed generation system. Understand what types of permits will be necessary for your system.
- ☐ Determine if you want to be off the grid or if you want to retain connection with the electric utility to receive power and to send excess power to the grid.
- ☐ Contact the utility provider to discuss DG systems and project plans. Determine interconnection requirements or any special permits required. **Iowa law requires that the distributed generation system owner notify the host utility prior to installing a distributed generation system.**
- ☐ Review the safety guidelines with the utility staff
- ☐ Plan that the state of Iowa or the electric utility will require an inspection upon completion.

Cost Considerations

- ☐ Estimate the cost of the system and the cost per watt of recommended capacity?
- ☐ Is there a performance guarantee?
  - How is it established?
  - What happens if the system does not perform as expected?

IUB Drafted Distributed Generation Checklist

- ☐ Determine the installed-cost comparison of leasing versus owning the system? If leasing, ask the following questions:
  - Who owns any renewable energy credits associated with the system, if the system is leased?
  - If leased, can a system be bought before the end of the lease term?
  - Who owns a leased system at the end of the lease?
  - Who pays to remove and repair the roof at the end of a lease, if a system is leased?
  - If a system is leased, who pays the taxes on it, including any increase in property taxes?
  - If a system is leased and the property is sold, what happens to the lease and the installation?
  - Who will be responsible for operation and maintenance of the system during the lease?
  - What is the lease payment structure and what is included in the contract?
- ☐ Determine the estimated payback period.

  Total Initial Cost / (Annual Energy Cost Savings – Annual Operating Costs) = Payback time, in years

- ☐ Determine the estimated annual maintenance expense.
- ☐ Investigate financing options and federal and state incentives with the Iowa Energy Center. Also, refer to the Database of State Incentives for Renewables and Efficiency. http://www.dsireusa.org
- ☐ Estimate any utility rebates and tax credits and requirements to utilize.
- ☐ Examine the financial assumptions regarding utility costs, continuation and terms of net metering, tax credits and production curves that were used when determining life-cycle benefits of the installation?
  - Understand that current electric rates are complex and vary depending on time of year, time of day, season, and volume used. Some fixed aspects of rates may not be offset by a DG system.
  - Future utility rates are difficult to predict and vary greatly when evaluating a price and any assumed savings. The U.S. Energy Information Administration provides forecasts of retail electric rates for the next 1-2 years by region in its Short Term Energy Outlook.
- ☐ Check with your accountant or tax advisor and property insurer to ensure that the appropriate policies are in place and tax obligations are met.
- ☐ Are there any required upgrades or home repairs needed to accommodate a DG system?
- ☐ Understand the financing options and the collateral requirements of each.

<u>After Installation</u>

- ☐ Track information to evaluate the performance of the distributed generation system.
- ☐ Stay in contact with the electric utility to ensure long-term efficient and transparent two-way communication.

IUB Drafted Distributed Generation Checklist

Helpful Links:

Attorney General - to file a complaint	http://www.state.ia.us/government/ag/file_complaint/index.html
State Fire Marshal Division (Licenses Electrical Contractors)	http://www.dps.state.ia.us/fm/index.shtml
Iowa Energy Center	http://www.iowaenergycenter.org/
Alliant Energy	http://www.alliantenergy.com/ http://www.alliantenergy.com/AboutAlliantEnergy/DoingBusiness/CustomerOwnedGeneration/index.htm
Iowa Association of Electric Cooperatives	http://www.iowarec.org/
Iowa Association of Municipal Utilities	http://www.iamu.org/
MidAmerican Energy Company	http://www.midamericanenergy.com/ http://www.midamericanenergy.com/rates7.aspx
North American Board of Certified Energy Practitioners (To see if your installer is certified)	http://www.nabcep.org/

Appendix C – Summary of Participant Responses

Table of Contents

Summary of Responses to Net Metering Questions

1. Various commenters recommended net metering policy changes which are listed below. Discuss the advantages, disadvantages, and the regulatory changes necessary to implement each suggested change.

MidAmerican Energy Company (MidAmerican)
MidAmerican made some general comments about the legal issues of making changes to the net metering rules. The Iowa Utilities Board (Board) had ordered MidAmerican to provide net metering, and MidAmerican appealed that decision.[19] "MidAmerican's Rate NM reflects the resolution of a litigation settlement regarding the Board's ability to order rate-regulated utilities to net meter." In a more recent decision, the Federal Energy Regulatory Commission (FERC) stated the following regarding its jurisdiction over net metering:

> The Commission has explained that net metering is a method of measuring sales of electric energy. Where there is no net sale over the billing period, the Commission has not viewed its jurisdiction as being implicated; that is, the Commission does not assert jurisdiction when the end-use customer that is also the owner of the generator receives a credit against its retail power purchases from the selling utility. Only if the end-use customer participating in the net metering program produces more energy than it needs over the applicable billing period, and thus is considered to have made a net sale of energy to a utility over the applicable billing period, has the Commission asserted jurisdiction. *Sun Edison LLC,* 129 FERC ¶ 61,146 (2009) at ¶ 18.

FERC stated that it would not assert jurisdiction over netting that occurs during the billing process for an individual home owner or farmer, but did not say that it would accept any net metering arrangement. In addition to the federal issues, the Board should also consider the impact of assigned exclusive electric service territories on electric utility service in Iowa.

Before making any changes to net metering, MidAmerican believes the Board should determine that distributed generation (DG) rates should result in other utility customers subsidizing DG customers.

a. Increase the size cap from 500 kW to 2,500 kW or 5,000 kW

Interstate Power and Light Company (IPL)
IPL does not support increasing the size caps for net metering. The Board's rationale in its order where IPL's net metering tariff was approved is still valid today. The Board stated, "Requiring a larger limit at this time could expose IPL shareholders to significant

[19] MidAmerican Energy Co., 94 FERC ¶ 61,340 (2001)

costs. As the Board has consistently notes, net metering is most practical for small, not large, customers." Docket No. TF-03-180-181, January 20, 2004, order, p. 5.

Also in a September 17, 2003, order where an industrial customer requested net metering for a 6 MW facility, the Board stated:

> While it is not necessary for the Board to address other arguments supporting and opposing the motion to dismiss, it should be noted that even though the Board's rules do not contain a specific limit on net metering, the Board reiterated in the March 8, 2002, MidAmerican order cited by IPL in its motion to dismiss that "net billing was designed for small customers installing renewable generation for their own use, rather than for large customers or commercial application." In orders and during the pendency of proceeding before the Federal Energy Regulatory Commission regarding net metering rules, the Board has consistently stated and followed this policy. While the rules do not contain specific limits on net-metered facilities, the Board does not envision a 6 MW commercial facility would qualify for net metering arrangements under the Board's rules. In the past, the Board has taken a balanced approach in supporting customers' installation of renewable facilities while avoiding unintended consequences associated with allowing larger facilities to be net metered. Docket No. FCU-03-38, pp. 5-6.

<u>MidAmerican</u>
Assuming that FERC does not take jurisdiction over a net metering arrangement that increases the size cap, the Board could increase the cap through a board order. However, MidAmerican believes that the Board should not increase it at the expense of non-DG customers. It would inappropriately provide a competitive advantage to businesses or residential customers who are in a position to take advantage of net metering over those who are not able to. All subsidies in the net metering rate should be eliminated before making any changes to the cap.

<u>Farmers Electric Cooperative - Kalona</u>
Caps should be a function of technical reality instead of a regulated or rate requirement. All units net metered in Iowa above 100 kW will typically fall under a demand rate structure and the net rate will be the energy only part of the retail rate. Net metering system size is restricted by the demand rate structure through the return on investment for the generation owner. A feed-in-tariff (FIT) and metering structure will eliminate this.

<u>Iowa Association of Electric Cooperatives (IAEC)</u>
The 500 kW size cap is included in MidAmerican and IPL's tariff and resulted from the settlement of a dispute concerning the lawfulness of the net metering requirement. There could be new legal challenges to the net metering requirement under the Public Utility Regulatory Policies Act of 1978 (PURPA) if the cap size were to change.

<u>Iowa Association of Municipal Utilities (IAMU)</u>
IAMU opposes an increase in the size cap for net metering for municipal utilities because it cannot be applied uniformly to municipal utilities. Peak demands among

Iowa's municipal utilities range from less than 10 MW to 50 MW. For the small municipal utilities, net metering even a 500 kW DG system is not practical. The local utility governing body should make decisions regarding the size caps of net metering and whether to offer net metering.

Missouri River Energy Services (MRES)
MRES believes that municipal utilities should maintain control over DG policies (like cap size) as they are better able to respond to the unique demographics and planning in the communities they serve. Energy generation above a municipal utility's peak would result in wasted energy costs distributed to other customers.

The municipal utility should have control of its net metering policy to minimize rate impacts and cost shifts to other customers. Net metering subsidizes certain customers at the expense of others on the system but it is not transparent. Non-DG customers are paying above market costs to the benefit of DG customers. DG power lowers electric sales leaving less revenue to pay fixed costs; again leading to higher rates among the non-DG customers.

Net metering can result in mandating purchases at above-market rates. It is imperative that municipal utilities maintain the role of making local decisions to most efficiently and reliably provide electric service. The costs associated with resource planning for the additional DG are difficult to control and include in long-term planning. Market impacts must be addressed as DG increases.

The Alliance for Solar Choice (TASC)
TASC supports an increase to the size cap but believes a size cap is unnecessary. Many states no longer use arbitrary system size caps but instead, focus on allowing customers to offset their on-site load as is economical and practical for them to do. For example:

- New Jersey has no specific size limits but, instead, limits system capacity so that it may not exceed the previous year's electricity consumption.

- Ohio limits system size to primarily offset the customer's load.

There would be significant improvement in the current Iowa net metering rules if the Board would remove the size cap to allow customers to meet their on-site energy needs. However, if the Board believes it is still necessary, TASC supports a cap at 2 MW (as set by twelve states including Florida and Vermont). This level is high enough to allow the majority of Iowa's customers to invest in renewable energy resources.

ELPC et al.[20]
The size cap needs to be increased to include larger customers and to be consistent with the national trends. Many institutional, governmental, industrial, agricultural, and large commercial customers would have on-site loads larger than 500 kW. Increasing the size cap needs to be done if virtual metering and aggregate metering is allowed. ELPC et al. support raising the cap to 5,000 kW but also supports an increase the cap to 2,500 kW.

Another option would be for the Board to remove the size cap but include language that limits the system size to 100 percent to 120 percent of customer load or average annual consumption.

Iowa Industrial Energy Group (IIEG)
IIEG opposes an increase of the size cap because it is concerned about the cumulative costs to consumers from net metered projects. If the Board were to increase the net metering project cap, costs to non-participating consumers would quickly mount.

Iowa Solar Energy Trade Association (ISETA)
Increasing the current 500 kW capacity cap would spur dramatic DG growth in our state.

Midwest Cogeneration Association (MCA)
The Board needs to increase the size of the cap to 2,500 kW or 5,000 kW to encourage combined heat and power (CHP) and waste heat and power (WHP) projects. Increasing the size cap will also encourage penetration of all types of DG and augment the capacity of Iowa's utilities.

Ben Grimstad
Mr. Grimstad supports increasing the size cap to encourage a greater impact.

All Points Power
All Points Power supports an increase in cap size and says that larger caps will increase renewable energy contributions, reduce the need for additional power, and provide increased societal benefit.

Energy Consultants Group
Energy Consultants Group supports increasing the size of the cap.

Luther College
Luther College recommends raising the cap to 5,000 kW to help achieve its Climate Action Plan and greenhouse gas reduction goals. Luther College would like to be able to produce all of its own power, but this would require three wind turbines. Currently, Luther College has one 1,600 kW wind turbine which sells its energy to its electric utility rather than being net metered. Due to the current net metering cap, Luther College

[20] ELPC et al includes: Environmental Law & Policy Center, Iowa Environmental Council, Sierra Club, Iowa Solar Energy Trade Association, Solar Energy Industries Association, the Vote Solar Initiative, and Interstate Renewable Energy Council.

would only be able to take 31.25 percent of the electricity from the wind turbine via net metering. Raising the cap to 2,500 kW would allow Luther College to net meter all the energy produced by its wind turbine. Raising the cap to 5,000 kW would allow it to produce all the energy it would needs.

Luther College Wind Energy Project
Iowa has one of the highest caps among the neighboring states in the Midwest but it is lower compared to other states such as California, Connecticut, Delaware, Maine, Maryland, New York, Oregon, Rhode Island, Vermont, and West Virginia which have caps that range from 1,000 MW to 10,000 MW. New Mexico has a cap of 80,000 MW. There appears to be no reason why the Board cannot consider a different cap since it is not clear how or why the 500 kW cap was determined.

The 500 kW cap reduces the amount of power that can be net metered, and high demand charges are another deterrent for large general service customers who want to install large DG systems.

John E. Carpenter
The size cap should not be increased. The Board should ensure that the price large generators seek from the utility for their energy is fair.

Industrial Energy Applications
Larger caps are needed to increase the size of projects that will then reduce the cost of installation per kW and increase the amount of capacity and energy produced. This will generally increase the societal benefit of renewables and DG.

b. Allow "virtual net metering" where a customer who is not personally able to own a DG facility could invest in a DG facility and receive a benefit from the energy produced by that facility.

IPL
IPL supports offering customers the opportunity to financially support renewable energy and currently does so through a variety of mechanisms. IPL's Second Nature™ program allows customers who do not own renewable facilities an opportunity to support renewable projects. Additionally, customers have the opportunity to purchase renewable energy certificates through the Midwest Renewable Energy Tracking System (MRETS®).

According to the Solar Electric Power Association,[21] virtual net metering allows net metering credits generated by a single renewable system to offset load at multiple retail electric accounts within a utility's service territory. As with traditional net metering, credits appear on each individual customer's bill. This potentially allows both the user and the generator to avoid paying costs that are incurred in the supply of utility service.

[21] Solar Electric Power Association Community Solar Handbook (Report #03-13), Version 1, December 2013, p. 16.

The arrangement would allow customers to wheel power across the transmission and distribution system from their generators to multiple locations within a utility's service territory to partially serve each account's load.

IPL believes that such a jointly-owned renewable system would be considered a public utility under Iowa Code § 476.1, which provides a limited exemption from the public utility definition if the renewable facility is furnishing electricity to five or fewer customers either by secondary line or from an AEP facility or small hydro facility, from electricity that is produced primarily for the person's own use. To qualify for this exemption, the renewable facility would need to construct and own the distribution lines from the generation source to the load, and use the majority of the power generated itself. The electricity produced clearly would not be primarily for an individual customer's use since multiple parties would have some type of ownership in the facility. Therefore virtual net metering is beyond the scope of the Board's rules and may require a change to Iowa's laws regarding the definition of a public utility as well as Iowa's exclusive service territory laws.

Regardless of the legal questions, the arrangement also fails simple economic pricing parameters and creates a slippery slope towards a system that allows a wide variety of power flows (without compensation) on a utility system.

<u>MidAmerican</u>
Virtual net metering is prohibited by Iowa law and creates a conflict with the Iowa service territory statutes. Iowa policy is that retail sales of electricity to Iowa consumers must be regulated, either by the Board, municipal government, or by rural electric cooperative (REC) consumers and their elected boards. Virtual net metering will increase the degree of cross-subsidization of customers. If virtual net metering is permitted, the Board should restructure the net metering rate to eliminate the subsidies inherent in the rate.

Allowing virtual net metering will potentially make DG investment more economic and could eliminate some problem issues related to DG ownership for customers. Utility (and possibly third-party) ownership of solar installations may allow for better utilization of tax credits, offer DG participation to customers without structural resources, and allow for DG facilities to be placed in areas where power flows would be less of a concern.

<u>IAEC</u>
Virtual net metering can create accounting or other issues if a customer's load is located in one service territory but the DG facility is located in another service territory. Also if there is distance between the customer and DG facility the customer is using the distribution system without adequately compensating the utility. Virtual net metering is not necessary for a customer to invest in a DG facility since the output from the DG facility can be sold to the interconnected utility and the DG customers can receive its share of the sales proceeds. The IAEC does not see a need to allow virtual net metering.

IAMU
The IAMU is aware of at least one virtual net metering situation within a municipal utility and knows there is a growing interest among other municipal utilities. Implementing virtual net metering may prove complex and costly and should be left to local decision-makers.

MRES
Municipal utilities and their members should decide if a project, such as a solar garden, fits into their power needs and consumption profile, and how to deal with the contingencies. Ownership of off-site generation poses several issues for utilities. When on-site generation is added, the customer's electricity requirements change but the utility's responsibility to provide reliable electricity remains the same. Additionally, the utility is now responsible for upgrades necessary to take power from the customer and pay for that power regardless of need. When a customer contracts with an off-site third party, it further complicates the process and passes on costs to non-participating customers.

There are also issues of wheeling the electricity over distribution and transmission lines and how costs and responsibilities are determined and allocated. Another issue is how the power and transactions are dealt with in the Midcontinent Independent System Operator (MISO) tariff. How the transmission or distribution congestion is dealt with is yet another issue.

ELPC et al.
Virtual net metering should be allowed because it will stimulate innovation, exploit economies of scale (in size and numbers of installations), and expand solar participation to a broader base of customers. This will allow more customers, such as renters or those whose property cannot accommodate a generation facility, to take advantage of self-generation. ELPC et al. support the broadest possible expansion of virtual net metering. Farmer's Electric Cooperative (based in Frytown) currently offers virtual net metering which allows customers to invest in a community solar garden.

Both Interstate Renewable Energy Council's (IREC) Model Rules for Shared Renewable Energy Programs and Vote Solar Initiative's Shared Renewables Policy contain resources for the Board to consider.

ISETA
Allowing virtual net metering for multiple meters will spur DG growth in Iowa.

Winneshiek Energy District
Virtual net metering is important for large and small customers. Large customers will benefit from increased financial footing to operate their businesses and small customers will have the ability to invest in DG even if they do not have the space.

Ben Grimstad
Mr. Grimstad is in favor of allowing virtual net metering. Mr. Grimstad knows many who want to invest in renewable and solar DG but can't because of location, size of investment, or tax situation. Virtual net metering would help more people participate in DG.

All Points Power
All Points Power supports virtual net metering as a means of promoting DG participation among customers who lack the resources to install individual DG projects. Virtual net metering allows for larger, more efficient, centrally managed DG projects.

Energy Consultants Group
Energy Consultants Group feels virtual net metering is a massive step forward.

Luther College
Luther College supports virtual net metering so it could invest in other renewable energy projects in Decorah, Winneshiek County, or other areas in Northeast Iowa. Virtual net metering would help solar gardens or community wind farms become economically viable.

John E. Carpenter
A group wanting virtual net metering should be able to incorporate as a single company that would have a net metering relationship with the utility.

Industrial Energy Applications
Virtual net metering would encourage DG participation and collaboration among customers. These projects can exist within utilities, private firms, or non-profit associations and would increase overall societal benefit of DG systems. Virtual net metering also allows for better land use management, by encouraging optimal solar benefits when space is available rather than just generating enough electricity to power the specific location.

c. Include combined heat and power (CHP) and waste heat and power (WHP) as net metering eligible facilities.

IPL
IPL believes the Board's policy has consistently been to allow net metering for small renewable (alternative energy production) facilities, not large commercial applications.

IPL's existing CHP customers are very large industrial customers taking service under IPL's Standby and Supplementary Service tariff. Extending net metering to CHP customers could negate provisions of the standby tariff. In addition, given the size of these qualifying facilities (QF), the delivery of excess CHP power under a net billing scenario into the electrical grid may actually be considered a wholesale transaction subject to FERC jurisdiction. The rate paid under net metering to these CHP facilities could be considered an incentive rate that is preempted by PURPA, to the extent they require a utility to purchase power generated by a QF in excess of avoided costs. (See FERC *Order on Complaint and Petition for Declaratory Order and Petition on Enforcement,* Docket No. EL95-51, January 29, 1997)

MidAmerican
Including CHP and WHP facilities in net metering presents legal concerns such as: whether CHP and WHP are within FERC's expectation of permissible net metered facilities and Iowa's Alternate Energy Production (AEP) definition does not include CHP and WHP facilities.

If the Board determines that CHP and WHP should be included in net metering, the rate should be restructured to eliminate increased cross-subsidization that will occur. MidAmerican recommends retaining the 500 kW size cap for these facilities as well as requirements that the net metering be at one site primarily to serve the owners. Use of standby tariffs is more appropriate for larger customers pursuing CHP and WHP.

IAEC
IAEC members that offer net metering do so to all eligible facilities which may include CHP or WHP facilities. Some CHP and WHP facilities may be ineligible due to size.

IAMU
The value of CHP and WHP generation varies greatly depending on a wide range of factors such as size, availability, capacity value of on peak, and cost of upgrading a distribution circuit to accommodate the facility.

MRES
The municipal utility and its citizen-owners understand the potential impact that CHP or WHP could have on the system. The municipal electric utility considers efficiency and reliability. If a proposed unit provides intermittent output, the municipal utility is left to come to terms with this inefficiency and plan the resources, the MISO/Southwest Power Pool market impacts, and the technical upgrades needed on the system to handle the power. For example, if the utility is not in need of the power, its impact on resource planning and costs could be dramatic. The reduced amount of electricity purchased from the municipal utility, shifts the cost of maintaining standby service shifts to the residential customers.

Additionally, if the CHP unit is producing more energy than the owner needs, the utility would be required to purchase that power, regardless of need, which would be paid for by other customers. Finally, other customers would pay for the stranded costs of the power purchase contracts or generation that the utility has already purchased to serve projected needs. Because the customer-owners would be the ones to deal with any inefficiencies or costs, it should be up to the customer-owners as to how CHP or WHP projects would be integrated into the utility and into their community.

ELPC et al.
ELPC et al. support the expanded use of clean, efficient technologies – including CHP. Some policies to support CHP include: improving the utilities' methodology for calculating avoided costs, improving standby tariffs, including CHP in energy efficiency programs, and exploring state tax incentives.

Since PURPA favors self-generation and reliance on cleaner, more efficient generation, and CHP generates energy at high efficiency, some of the ELPC et al. parties would support net metering for CHP in appropriate circumstances. Net metering CHP best practices from other states, including minimum efficiency levels, should be considered.

MCA
The Board should include CHP and WHP in the list of eligible facilities for net metering. Without net metering as an option, small CHP and WHP project developers have to enter into interconnection and power purchase agreements (PPAs). Net metering allows them to sell back excess power to the grid with a simplified mechanism, which improves the viability of the project.

Winneshiek Energy District
Providing net metering opportunities will be key for encouraging larger users to build CHP and WHP facilities.

Luther College
Current high demand standby and tariff charges make including CHP and WHP as net metered eligible facilities unattractive to ratepayers in Iowa.

John E. Carpenter
Mr. Carpenter supports including CHP and WHP in net metering.

Industrial Energy Applications
Industrial Energy Applications supports net metering of CHP and WHP projects, as well as the sharing of energy outputs by adjoining property owners, in a way that these exchanges do not constitute energy sales. Archer Daniels Midland and Red Star, located in Cedar Rapids, currently have such an arrangement. Changes in the Iowa Code and utility tariffs might be needed so smaller projects (and perhaps projects which are not on adjacent properties, but are within distances to share thermal outputs) can benefit from these arrangements. These arrangements will lead to an increase in the number and size of CHP and WHP plants and higher overall energy conversion efficiency.

d. Allow an annual cash-out of the net metering balance.

IPL
If net metering is retained with the current rate design, IPL not only supports a minimum annual cash-out (at avoided cost rates) but believes it is more appropriate to cash-out

monthly. Excess generation payments[22] used in future months can end up costing more than the full retail rate depending on when the power was initially received by the utility. Iowa should also consider a cap on excess generation of 10-20 percent of annual energy from a QF (i.e.: cogeneration facility or small power production facility) as many other states do. Finally, IPL would favor a change to the rule[23] to allow net metered kWh (generation greater than energy used) to be considered a cost of purchased power recoverable through the energy adjustment clause.

MidAmerican
A net metering arrangement converting to a cash-out may require FERC approval. An annual cash-out of the net metering balance is inconsistent with the goal of allowing net metered customers to largely self-supply their own electricity needs and there should not be a large balance available for cash-out. If the Board is authorized and decides to allow an annual cash-out, it should consider limiting the amount cashed out to no more than 5 percent of a customer's annual DG production to prevent subsidization.

IAEC
Of the IAEC members that offer net metering, some allow for or require a cash-out (i.e., on a monthly or annual basis). One needs to determine the intent of net metering before determining whether the cash option is allowed. Cashing out would change the nature of the transaction because MidAmerican's and IPL's net metering is based on the premise that there is no sale or purchase, just netting kWh against kWh.

IAMU
Many municipal utilities offering net metering provide for an annual cash-out of the balance. The rate and whether it is done should be set by each municipal utility's governing body.

MRES
No rule changes are required to allow municipal utilities the option to allow an annual cash-out of the net metering balance.

TASC
TASC believes the current indefinite roll-over of net metering credits is sufficient and should be maintained. This approach creates customer incentives to limit the size of a DG system to serve no more than the customer's long-term on-site energy needs, avoiding the need for specific system size limitations that may reduce self-supply opportunities for some customers. By not cashing out, the customer avoids adverse tax and regulatory consequences that occur when energy is sold as part of the net metering arrangement. Iowa's current net metering practices could be improved by rule revisions clearly stating that indefinite carryover of excess generation is the chosen crediting practice.

[22] As discussed on page 29 of the Net Energy Metering Primer, July 2013.
[23] 199 IAC 20.9(2).

<u>ELPC et al.</u>
ELPC et al. believe that the customers should have the option to roll-over credits into the next year to provide maximum flexibility. If customers choose to cash out balances, they need to be advised of the potential federal and state tax consequences. Freeing the Grid[24] suggests excess generation should be priced no lower than the average daytime wholesale price for the prior year.

<u>ISETA</u>
Allowing the banking of excess kWh and selling excess generation yearly at the retail price would spur DG growth in Iowa.

<u>MCA</u>
MCA recommends that Board regulations allow net-metered customers to elect to be compensated in the form of an on-bill credit for excess exported power generation or receive a direct payment on a quarterly or annual basis. This will ensure fair compensation and will allow the utility and the customer to clear their books at a defined time.

<u>Winneshiek Energy District</u>
The ability to cash out at least up to a certain percent of annual production will be key to reducing the incentive for large-scale storage installations and islanding or grid defection.

<u>All Points Power</u>
All Points Power supports an annual cash-out of net metering balances. The cash-out option would give customers an incentive to install optimal capacity systems resulting in increased DG and reduced reliance on central power plants and transmission systems.

The current avoided cost methodology allows for payments to facilities that have excess generation under PURPA. Annual net metering cash-outs will extend the same methodology to DG customers.

<u>Energy Consultants Group</u>
Energy Consultants Group supports allowing an annual cash-out of the net metering balances.

<u>Luther College</u>
Luther College supports a cash payment for the excess account balances at the end of the twelve month period with a limit of 120 percent of total annual consumption.

<u>John E. Carpenter</u>
Mr. Carpenter believes there should be an annual cash-out for net metering.

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[24] Freeing the Grid, Best Practices, *available at* http://freeingthegrid.org/#educationcenter/best-practices (last visited June 24, 2014).

Industrial Energy Applications

Industrial Energy Applications supports an annual cash-out of net metering balances. The current avoided cost methodology allows for the payment to facilities that have excess generation under PURPA. Allowing an annual cash-out of the net metering balance would effectively extend the same methodology to DG customers. Payouts should take into account the value of on-peak versus off-peak production.

e. Include aggregate metering for customers who may have more than one meter on their premises.

IPL

IPL supports meter aggregation for customers with more than one meter on an existing premise through its primary metering policy, and related terms of service. A customer with multiple meters can own the secondary transformation and secondary lines outright by moving the metering to the high side of the customer-owned transformer. Also, the customer can pay IPL an excess facilities charge for the dedicated distribution facilities to allow the consolidation of the metering. Without these considerations, customers will want aggregated metering across multiple facilities without covering the related costs.

MidAmerican

MidAmerican assumes aggregation behind the meter where one customer has multiple meters not relying on the utility distribution system. Any other type of aggregation would be retail wheeling which may result in the wholesale sale of power subject to FERC regulation. Efforts should be made to ensure aggregation does not result in preferential treatment under standard filed rates.[25] DG customers should not be permitted to engage in retail wheeling using MidAmerican facilities.

IAEC

There is nothing in PURPA or the Board rules precluding a DG customer from serving multiple loads on its own premises, as long as the DG customer is generating primarily for its own use. Neither Iowa law nor PURPA require a utility or allow a DG customer to use the facilities of the utility to provide the service that aggregate net metering would essentially allow. The concept of aggregate net metering calls into question whether or not net metering can continue to be treated as a metering arrangement instead of a purchase and sale.

IAMU and MRES

Aggregate net metering exacerbates concerns of a one-size-fits-all approach for municipal utilities.

TASC

TASC supports aggregate net metering for electric customers in Iowa to efficiently allow DG to serve on-site load. In Iowa there are many agricultural customers who typically

[25] For example, combining usage on more than one netted meter should not let a customer move from a medium to a large volume rate.

have multiple meters on their property for pumping water, drying crops, powering residential and non-residential buildings, and other activities. Aggregate net metering can be implemented in a way that either restricts eligible meters to a contiguous property, or allows all of a customer's meters to qualify without geographical limitations.

ELPC et al.
Aggregate metering should be allowed since there are many reasons to have multiple meters at contiguous physical locations and there are no physical or technical reasons to prohibit aggregate metering for these customers. Customers[26] can realize economies of scale by aggregating several loads and offsetting them with a single DG facility.

Iowa Nebraska Equipment Dealers Association (INEDA)
INEDA supports the expansion of net metering in Iowa to allow customers with multiple meters to aggregate loads against the customer's generating system. "INEADA believes policies that enable customers to examine their own needs and demands and offer choices in how they contribute to the overall energy system have the potential to benefit all customers."

INEDA offers the following comments to enhance the current net metering policy:

1. Aggregate net metering is a valuable addition to current net metering policy and encourages investment in renewable energy.

    - Aggregate net metering expands options for customers who wish to install wind, photovoltaic (PV), or other renewable generation facilities by utilizing a single generating system to offset electricity measured by multiple meters. Meter aggregation greatly improves the economic payback for customers, they benefit from economies of scale in system sizing and it removes some obstacles associated with site limitations.

    - Aggregate net metering potentially benefits many types of customers, but can be particularly beneficial to customers with multiple meters and/or electric accounts, such as agricultural producers. Agricultural customers often have multiple meters on a single property and aggregate metering permits system sizing to their unique needs.

2. Aggregate metering is already adopted in many states.

    - In the Midwest, Minnesota, Illinois, Arkansas, and Colorado incentivize on-site generation for multiple-metered customers through explicit meter aggregation rules. These policies play an influential role in determining the opportunities that aggregated net metering may offer customers. INEDA encourages the Board to consider the IREC's Model Net Metering Rules, 2009 edition, as a

[26] Such as school districts, institutions, government jurisdictions, multifamily housing, agricultural customers and commercial real estate properties.

template to develop its aggregate net metering policy.[27] At the most basic level, INEDA wishes to add aggregate net metering language providing that a single customer may be able to offset multiple billing meters, regardless of rate class, located on the same property (or adjacent/adjoining properties) with credits from a single renewable generation system and that the owner of the generating system be the owner of all of the meters and that the property be owned or leased by that same customer.

3. Aggregate net metering does not create cost shifting.

- In INEDA's experience, utilities report concerns that an expanded net metering policy implicates cost recovery issues and shifts costs onto non-participants. Utilities assert that in order for the net metering program to remain revenue-neutral, these charges and fees, as well as any additional administrative costs due to aggregate net metering, would need to be recovered from program participants or such costs would otherwise have to be shifted to non-participating customers.

- While INEDA understands the view point behind these concerns, it should be noted that aggregate net metering is merely a logical outgrowth of net metering policy designed to address the unique circumstances of customers with multiple meters. Allowing customer-generators to aggregate their load from multiple meters will not result in an increase in the expected revenue obligations of customers who are not eligible customer-generators. Today's electric rates already bake-in the costs associated with net metering programs and the aggregation of meters is merely an administrative variation of the current application of the net excess kilowatt-hours.

- Self-generating customers are investing substantial sums to build generation, to become a system resource which will, in the long term, allow utilities to avoid making generation and possibly other investments, which reduces the amount of fixed costs to which other ratepayers must contribute. As electrical utilities continue to experience load growth, on-site generation facilities offer benefits to all customers by helping utilities meet new generation capacity needs. Short term, the current amount of installed nameplate capacity is small and it is unlikely that any transition in Iowa's net metering rules would result in rate impacts or a radical hike in participation of net metering. INEDA believes aggregate net metering is a valuable add-on to Iowa's net metering policies and can encourage additional investment in renewable energy.

<u>ISETA</u>
Allowing virtual net metering for multiple meters would spur DG growth in Iowa.

[27] *See* Net Metering Model Rules (IREC), 2009, subsection (d), *available at* www.irecusa.org/wpcontent/uploads/2009/11/IREC_NM_Model_October_2009-1-51.pdf.

MCA

MCA believes net metering aggregation for an individual net metering customer is a good idea. Aggregated net metering will allow industrial, non-profits, and other businesses that have multiple meters to aggregate for billing purposes. Recent legislation in Minnesota[28] now requires public utilities to aggregate meters for net metering customers on request. There should be a public rulemaking docket to determine how aggregation will be implemented.

Winneshiek Energy District

Schools and local units of government will benefit from aggregate net metering because they often have a large number of buildings and meters spread over a significant geographic area.

All Points Power

All Points Power supports metering aggregation for customers with more than one meter on the same property. IPL already supports this for large industrial customers and the same practice should be extended to all customers. Project costs increase the requirement to physically interconnect to multiple meters, but the reliance on transmission and distribution systems is reduced.

Energy Consultants Group

Energy Consultants Group agrees with including aggregate metering for customers who may have more than one meter on their premises.

Luther College

Luther College believes that aggregated metering will encourage additional DG in Iowa.

John B. Cook

Aggregate metering could make it feasible for the owner of an apartment building to install solar panels which would be shared by all tenants.

John E. Carpenter

Mr. Carpenter supports allowing multiple meter locations if the utility can do it and it is technically stable.

Industrial Energy Applications

Industrial Energy Applications supports metering aggregation for customers with more than one meter on the same property. IPL already supports this for large industrial customers and the same practice should be extended to all customers.

[28] Minnesota Statutes 2012, Section 216B.164.4a

2. How does the utility account for energy “purchased” through net metering when reporting fuel type information to the Board, the United States Energy Information Administration, the Federal Energy Regulatory Commission, and others?

IPL

Net metering is not currently reported as an energy purchase. IPL supports a change to 199 IAC 20.9(2) to reflect all energy produced in excess of that consumed by the customer as an energy purchase. This will result in more accurate reporting to the Board, the United States Energy Information Administration (EIA), and FERC than having it reflected as a reduction to kWh sales.

MidAmerican

MidAmerican does not purchase energy through net metering. DG produced energy reduces retail sales and can only be used to offset electric service through the billing process.

Farmers Electric Cooperative - Kalona

Farmers Electric Cooperative believes this is not accurately possible with net metering.

IAEC

The IAEC believes that for the RECs there is no fuel type reported in net metering arrangements to the entities identified by the Board.

IAMU

Municipal utilities report the annual net amount of energy sold back to the utility on the EIA’s Annual Electric Power Industry Report (Form EIA-861).

ELPC et al.

There is no purchase with net metering. Consumption is offset and the Board said "net metering does not involve separate purchase and sale transactions but is essentially a metering arrangement."[29] FERC also stated that "no sale occurs when an individual homeowner or farmer (or similar entity such as a business) installs generation and accounts for its dealings with the utility through the practice of netting."[30]

[29] Iowa Utilities Board, Docket No. PURPA Standard 11, Order Regarding PURPA Standard 11 at 3 (August 8, 2006).

[30] Federal Energy Regulatory Commission, MidAmerican Energy Company Docket No. EL99-3-000, Order Denying Request for Declaratory Order (March 28, 2001).

3. Provide a list of the REC and municipal utilities who currently offer net metering. Also provide the applicable tariff or policy describing the net metering option.

IAEC
The IAEC has been advised that 23 RECs,[31] that are members of the IAEC, offer net metering and their tariffs are on file with the Iowa Utilities Board.

IAMU
There are 17 municipal utilities[32] that offer net metering.

MRES
None of the 19 Iowa MRES-member municipal utilities offer net metering. MRES purchases energy or capacity from any qualified facility that offers to sell the energy or capacity based on FERC rules and consistent with PURPA. Rates are based on avoided costs as defined by PURPA.

ELPC et al.
REC and municipal utility net metering policies vary by utility and are not transparent or easy for a customer to access or understand. It is important to understand the net metering options offered by RECs and municipal utilities to ensure that all Iowa customers have an opportunity to take advantage of net metering services.

EcoWise Power
MidAmerican and IPL customers have an advantage over REC and municipal utility customers in regard to incentives and opportunities for DG systems. Many RECs offer net metering programs, but have restrictive policies regarding use. Following are some examples:

- IPL and MidAmerican offer net metering for DG systems up to 500 kW. Any net excess generation is credited at the retail rate and carried forward indefinitely.

- Harrison County REC and Raccoon Valley Electric Cooperative allow net metering on systems under 50 kW, crediting any net excess generation on an annual basis at their avoided cost rate.

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[31] Allamakee-Clayton Electric Cooperative, Inc., Calhoun County Electric Cooperative Association, Consumers Energy, East-Central Iowa REC, Eastern Iowa Light and Power Cooperative, Farmers Electric Cooperative, Inc., Franklin REC, Guthrie County REC Association, Harrison County REC, Hawkeye REC, Heartland Power Cooperative, Iowa Lakes Electric Cooperative, Linn County REC, Lyon REC, Midland Power Cooperative, Nishnabotna Valley REC, North West REC, Osceola Electric Cooperative, Inc., Prairie Energy Cooperative, Raccoon Valley Electric Cooperative, T.I.P. REC, Western Iowa Power Cooperative, and Woodbury County REC.

[32] Ames, Atlantic, Bloomfield, Cedar Falls, Dayton, Estherville, Guttenberg, Independence, Lake Mills, Maquoketa, Milford, Mount Pleasant, Muscatine, New London, Traer, Waverly, and Winterset.

- Eastern Iowa REC and Nishnabotna Valley REC allow net metering on systems under 40 kW, crediting any net excess generation on an annual basis at their avoided cost rate.

- Iowa Lakes Electric Cooperative has a form of net metering where rather than receiving credits for net excess generation at the end of the year; the member receives a credit for any net excess generation at the avoided cost rate at the end of each month.

- Midland Power Cooperative had a limited amount of capacity in their net metering program so they maintain a waiting list of members who want to install larger net-metered DG systems (under 50 kW). After the Midland Power merger with Humboldt County REC, their area increased but the capacity of their net metering program remained the same.

- Hawkeye REC has a net metering program that allows members to install systems up to 40 kW. At the end of the year, members are paid at the retail rate for any net excess generation.

- Heartland Power Cooperative had 250 kW of capacity in their net metering program, which is now fully subscribed so additional members cannot net meter.

- Southwest Iowa REC does not allow any form of net metering at all. Chariton Valley REC has similar policies.

- Algona Municipal Utilities, as of a couple of months ago, did not have any DG policies. There are a couple of potential customers interested in installing DG systems; however, they have been waiting several months for interconnection and net metering policies to be established by the City in order to allow them to proceed.

- North West REC offers net metering on systems up to 50 kW, but they are only offering a total of 500 kW of capacity on this program.

In addition to soliciting comments from utility customers, installers also have valuable insight as to establishing DG systems in Iowa. Often, the policies of the electric utilities discourage growth. Many of Iowa's REC, municipal utility, and IOU customers are discouraged by the policies that do not allow them to take advantage of the federal and state incentives. Iowa needs to establish a statewide policy to establish consistent DG rules and policies.

4. For the REC and municipal utilities currently offering net metering, how do customers learn about the net metering program? For the REC and municipal utilities that do not offer net metering, explain why net metering is not offered.

<u>IAEC</u>
The IAEC believes REC member-owners learn about net metering the same ways that customers of investor-owned utilities (IOUs) learn about net metering which include; communications from the REC, member-owner inquiries, and individuals that market and sell DG facilities.

RECs not currently offering net metering have likely not had enough local interest or the local board of directors has decided not to offer net metering. The financial impact varies from utility to utility and may not be feasible for all locations.

<u>IAMU</u>
Net metering information and policies are readily available from the utility upon request and in some cases the information is on the municipal utility's or city's web site. Currently, 32 of 136 municipal utilities have DG facilities interconnected to their systems. The IAMU has developed a model net metering policy for adoption by municipal utilities and is working with members on adopting the policy that significantly reduces time and cost for municipal utilities in implementing DG policies and is accelerating adoption of policies.

When a utility compensates a customer for generation using net metering, they are paying the customer the retail rate, which includes both energy costs and distribution system costs resulting in the utility paying a higher cost for the energy from the DG customer. Energy purchased via net metering at the avoided cost would prevent cross-subsidization.

<u>MRES</u>
None of the 19 Iowa MRES-member municipal utilities offer net metering. The reasons for not offering vary from cost concerns, rate structure fit, and lack of local interest.

<u>Energy Consultants Group</u>
There is a lack of awareness among customers about availability and options.

5. Currently Iowa does not offer FITs. Explain why you think FITs should or should not be implemented in Iowa. In your discussion, address the advantages and disadvantages of both net metering and FITs.

<u>IPL</u>
IPL defines a FIT as a policy mechanism designed to accelerate investment in renewable energy technologies. Iowa already offers FITs to the extent net metering provides an incentive for renewable energy technologies. The state of Iowa needs to

determine whether there should be a FIT policy; whether the state supports payments made to renewable generators that will incent development and potentially raise utility prices; and to what degree such payments or tariffs are preferred - given the overall renewable generation position already enjoyed by the state, the declining costs of DG, and other customer equity factors.

<u>MidAmerican</u>
Both FITs and net metering hypothecate value of DG deliveries to the grid. FITs are somewhat more transparent than net metering but are often set based on the price (not value) that DG proponents claim they need in order to make a profit on DG installations. Neither approach measures the value to customers of DG deliveries to the grid. It is critical to keep in mind that Iowa retail customers pay for net metering or FITs.

FITs should not be implemented in Iowa for the following reasons. FITs typically involve long-term commitments at a fixed rate set above avoided cost. This mechanism effectively shifts economic risk from the supplier to the purchasing utility and its customers and results in higher costs for energy supply for customers since rates are set above system avoided cost.

Once the term has ended, a lower rate is usually negotiated with the supplier. The argument can be made that at this point customers benefit from a lower rate. However, there is no guarantee that the supplier will still be producing at that point or that customers are held harmless over the full life of the purchase, even if the facility continues to operate. If the state decides to encourage these types of facilities, it would be better to be transparent through expanded use of tax credits or other mechanisms that provide direct, defined benefits to the facility owners.

There are also regulatory and legal aspects to FITs that need to be considered. A series of orders issued by FERC have authorized FITs in limited circumstances. Specifically, these orders clarified that there can be multi-tiered avoided cost rate structures, but they must be consistent with the PURPA requirements. FERC reasoned that states have the prerogative to favor the development of particular types of generation resources, such as through renewable portfolio standards (RPS), and that these generation costs will be relevant to the determination of avoided cost for those procurement activities. FERC also clarified that bonuses or adders that are not reflective of avoided costs, although outside the confines of PURPA, may be authorized by a state through the creation of renewable energy credits to recognize environmental attributes.

In enacting Iowa Code § 476.41-44, the Legislature established an RPS for Iowa and determined the avoided costs for the resources used to meet that obligation. In Docket No. AEP-07-3, the Board found that the obligation was satisfied for MidAmerican and that any changes in resources used to meet these obligations would require Board approval. In order to have multi-tiered avoided costs, it would seem that the Board would need to create an additional RPS. It would be inconsistent with Iowa law for the Board to take such action on its own. While a FIT sounds like an innocuous regulatory action, the Board would exceed its statutory authority and violate PURPA if it were to adopt a FIT without a new RPS. MidAmerican believes that Iowa has demonstrated that substantial renewable assets can be built without a large RPS. In light of such success, a law providing for a FIT is unnecessary.

Consumer Advocate

Both FITs and net metering are policies adopted to encourage DG. A leading argument against FIT legislation proposed in Iowa has been that the Board's net metering rule already addresses compensation. There is less need for FITs in jurisdictions where net metering is widely available. The Consumer Advocate considers the Board's net metering rule to meet the foregoing parameters, but it is limited to the service territories of Iowa's rate-regulated utilities. A number of RECs have voluntarily adopted some form of net metering. The utilities' responses to questions about the number and size of DG interconnections on their systems may be useful in evaluating whether voluntary efforts or state and federal tax incentives have been effective in supporting Iowa's policy of encouraging DG in service territories of non-rate-regulated utilities. Markedly less DG interconnected with Iowa's non-rate-regulated utilities or customer concerns about DG policies in these territories may indicate a policy gap and a need for expanded application of net metering rules or FIT provisions in order to assure that the policies for encouraging renewable DG are available throughout Iowa.

Another reason cited against FIT policy in Iowa has been a desire not to re-open an issue that would likely result in extensive litigation and therefore take several years to implement, similar to what occurred with the Board's implementation of Iowa's AEP law, Iowa Code §§ 476.41-476.45, and net metering rule. A leading issue with a FIT law would likely be whether the provisions are consistent with PURPA's avoided cost criteria. FIT policy must be carefully crafted to ensure it is consistent with federal law. It could be challenging to develop FIT policy that is commonly regarded by interested stakeholders as both effective for encouraging renewable DG and compliant with federal law.

Iowa's net metering rule does not distinguish between different types of DG and, unless tied to time-of-use (TOU) rates, does not recognize the unique production characteristics of different DG resources. FITs can be structured based on the size and generating characteristics of the particular DG resource but would still be subject to PURPA avoided cost standards. Generally, a FIT can more precisely recognize unique generation characteristics that are to be taken account of in avoided cost pricing and can be adjusted to reflect changing avoided cost factors and methodologies.

For example, California's FIT program adopted a new pricing mechanism so that owners of DG renewable projects will receive market-based prices.[33] A starting price is based on the weighted average contract price of the utility's highest priced executed

[33] *In re: Order Instituting Rulemaking to Continue Implementation and Administration of California Renewables Portfolio Standard Program*, Rulemaking 11-05-005, Decision Revising Feed-in-Tariff Program, Implementing Amendments to Public Utilities Code Section 399.20 and Denying Petitions for Modification (Cal. PUC, May 5, 2011).

contract resulting from a renewable auction mechanism and is adjusted according to whether the accepted project delivers base load, peaking as-available, or non-peaking as-available electricity. A monthly price adjustment mechanism, based on the market response, is also utilized, and accepted projects are paid a time-of-delivery adjustment. Competitive procurement methods were recently adopted in Maine, Oregon, Rhode Island, and Vermont.

Farmers Electric Cooperative - Kalona

Implementation of a FIT will improve DG, will allow for more accurate measuring than net metering, and provide full accountability of financial benefits for the buyer and seller. The requirement of a separate meter allows for the tracking and monitoring of energy for systems analysis, reliability issues, environmental attributes, engineering studies and more. Rates can be structured, regulated, adjusted, and could eliminate cross-subsidization inherent to net metering.

IAEC

The IAEC suggests that there may be questions whether the Legislature has granted the Board authority to fund FITs and whether the funding for FITs would come from tax structure or Board assessments.

There are many incentives already available, allowing an individual or entity to invest in a DG system with very little capital risk. The intended outcome of an additional FIT incentive should be thoroughly evaluated prior to implementation. The impact of an incentive may have an unbalanced effect on utilities and may also impact low-income users.

IAMU

Municipal utilities support DG incentives when costs are fairly allocated and value is accurately accounted. Municipal utilities are opposed to a mandatory FIT, because other customers are paying the incentive to one customer and the incentive may encourage DG growth beyond the utilities supportive capacity. Municipal utilities support optional separate tariff rates for DG, but local control over design of individual FITs should be retained by the municipal utility.

MRES

Traditionally, FITs are used as a tool to encourage DG development and require utilities to buy all power at a rate higher than market value. The decision to offer a FIT and at what rate should be a decision made by customer owners and municipal utilities. Any FIT or DG policy adopted by the state is difficult to change to meet the specific load profile of an individual utility.

FITs are not necessary in Iowa to incentivize renewables. Iowa leads the nation in wind installation and reached this post without a renewable energy standard or a FIT. Renewables in Iowa will continue to grow due to Iowa tax credits, utility choices, state citing rules, and implementation of the Environmental Protection Agency (EPA) requirements.

Cost is a concern for implementation of FITs for municipal utilities. Because the FIT rates are above retail or wholesale electricity rates, ratepayers will have to absorb the higher electric rates. With FITs, the public forum to determine the value and viability of a project will not be preset. Any decision on FITs needs to be kept local in order to deal with cost shifting, technical, safety, and reliability aspects of FITs. A current example of FITs not working is Germany. Because of the lack of coordination in planning, interconnection, and deployment of DG, Germany experienced costly infrastructure upgrades to handle the load and had other technical challenges.

Finally, mandating a FIT runs contrary to federal law. PURPA requires that rates for purchases from cogeneration or DG must be just and reasonable to electric consumers and the public. PURPA also states that utilities shall not be required to pay more than avoided costs for any excess energy produced by an alternative energy project.[34]

<u>TASC</u>
Net metering policies have been used in Iowa for 20 years to facilitate and support the development of DG systems. Net metering rules have been a proven stable policy for DG participation that have adapted as needed to meet the needs of Iowans. FITs relative to net metering have significant tax disadvantages that include potentially jeopardizing access to tax credits and possibly having to be included in a taxpayer's reported taxable gross income. Set prices of FITs can be too high or too low and prove to ultimately be an unstable program to support DG system development.

<u>ELPC et al.</u>
There are several varieties of DG regulatory tools that may be appropriate to utilize in meeting specific policy goals. ELPC et al. has defined some of the available tools[35] and discussed the options available to design programs. Any one of these programs and tools may be appropriate depending on the particular circumstances and regulatory goals. The choice between tools is not mutually exclusive, and they can be deployed in combination to provide strategic and flexible support for a growing DG industry. Therefore, ELPC et al. recommend as a general rule, policymakers make an effort to provide customers with choices and options so that they can select the program that works best for them.

With respect to the advantages and disadvantages of net metering and FITs, there are several considerations to keep in mind. FITs require an administrative determination to set the appropriate price which has proven to be a challenge in many cases because it is difficult to get the rate exactly right. If the rate is locked in too high or too low the result may be either a stunted market or an overheated market that is difficult for growing a sustainable market. A FIT may be less appealing to investors because it may change periodically depending on how it is structured.

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[34] See 16 U.S.C.S. § 824a-3(b); Windway Technologies, Inc., v. Midland Power Cooperative, 696 N.W. 2d 303 (Iowa 2005).

[35] The tools include: tariff, a PPA, a standard-offer PPA, an avoided cost tariff, an avoided cost standard-offer PPA, a value of solar tariff, a value of solar standard-offer PPA, and PURPA net metering.

Deployment of a new FIT can typically catalyze very rapid market growth if that is one of the goals of the program providing an important boost to net metering in markets where retail rates are low to catalyze market growth on their own. The FIT program can then be scaled down in a transparent way to provide a bridge to a longer-term sustainable DG market based on net metering.

Net metering preserves a customer's ability to self-supply their own property using on-site generation which is very important to some customers and businesses. In contrast, FITs are typically structured as a wholesale transaction in which the customer sells or is credited all of their on-site energy production. This can have tax consequences which are important to consider.

Net metering has served as a fundamental, bedrock policy for supporting customer generation in states that have a healthy and growing DG markets. It is important to preserve and expand net metering in Iowa at this critical stage of market development. FITs and other appropriately designed regulatory programs should be explored as supplements to a strong net metering program to more quickly ramp up the DG market in Iowa. Long-term, more sophisticated policies and regulatory tools could be developed in the context of a comprehensive regulatory process that considers the paradigm shift to a more decentralized electricity grid.

Energy Storage Association (ESA)
ESA does not take a formal position on net metering policy; each state has its own regulatory construct with commensurate rules and policies that enable DG. Net metering cannot be simply replaced with a FIT. A FIT enables long-term certainty of price but does not account for daily price differentials. Any tariff would need to account for services for both injection and withdrawal; generally a FIT accounts only for injection. ESA recommends, instead, that net metering rules include behind-the-meter storage which could prove useful in scaling on-site storage as well as in fully realizing the benefits of solar rooftop systems and other distributed energy resources.

If net metering is extended to energy storage, ESA recommends that behind-the-meter energy storage assets be able to net their injections from their withdrawals when assessed transmission and distribution charges as a retail customer. Net metering has been effective in opening up markets for DG and is a proven policy mechanism that can support the widespread deployment of DG.

IIEG
IIEG believes that FITs should not be implemented in Iowa due to concerns that the associated costs would be paid by non-participating energy consumers and would subsidize the installation of DG through FITs.

The terms FIT and incentive rate have been used interchangeably in this docket. The term FIT has come to encompass any agreement for the purchase of electricity that includes a fixed price, a set duration, standard terms and conditions, and the right of a seller to interconnect to a utility's delivery system.

An incentive rate could represent anything ranging from a tariff-based credit for interruptible rates to a full-blown FIT. What falls under the incentive rate category usually involves a price signal based on a utility's existing rate structure and reflects the cost of conventional (typically fossil fuel power) generation. In contrast, the electricity prices included as part of a FIT are typically based on the costs inherent in the particular form of alternative energy under consideration and may bear no relationship whatsoever to the cost of conventional power, a utility's tariffed rates, or power prices in established energy markets, such as the ones operated by MISO in Iowa.

Net metering offers two distinct advantages over FITs. First, the amount of energy produced under net metering arrangements is generally limited to the amount of energy a participating customer requires. Second, net metering arrangements have a built-in ceiling for the price of electricity produced, namely, the retail rates charged by the utility and approved by the Board (for rate-regulated utilities). In some jurisdictions, FIT arrangement have been established that allow participants to sell to utilities amounts of electricity far beyond any needs of the utility for additional capacity and at prices that are what local wholesale markets can bear or what utilities charge in retail rates. FIT systems in Spain, Germany, and Canada have all opened with high participation, but due to the disproportionate rates, resulted in a negative impact on non-participating ratepayers.

MCA

Net metering is a stream-lined mechanism for transmitting relatively small amounts of excess power from DG utility customers back to the grid, whereas FITs provide a streamlined approach for larger DG projects and for encouraging the development of larger CHP and WHP projects. FITs provide transparent project parameters that allow prospective developers to plan and assess projects. MCA would encourage the Board to consider a FIT program for CHP and WHP projects.

Sierra Club – Iowa Chapter

FITs promote DG by providing for a long-term fixed contract that may be used by a renewable energy owner as collateral for a loan. FITs benefit both the utility and the DG owner by setting fixed prices for fixed periods of electricity rates. In contrast, net metering has the advantage of reducing the owner's energy bills but does not help with equipment expenses.

The Board has discretion in designing the FIT. A decision by FERC[36] has made it clear that a state can make separate avoided cost calculations if the utility is required to purchase electricity from different sources.

[36] FERC's decision in California Public Utilities Commission, 133 FERC ¶ 61,059 (October 21, 2010), clarified by FERC in its order denying rehearing, 134 FERC ¶ 61,044 (January 20, 2011) held that if a state requires utilities to purchase electricity from renewable sources, it may set avoided costs for the types of electricity that the utility must purchase.

Winneshiek Energy District

Net metering and FIT are both attempts to fairly value DG and compensate owners. FITs have been used internationally in support of renewable energy policy goals and normally have fixed time and prices. Net metering is a simpler approach resulting in a 1:1 production/consumption bill credit. At least 40 states have net metering programs providing retail value up to a customer's usage, and many of those same states have programs similar to FITs. Winneshiek Energy District supports further study into development of a FIT in Iowa, suggesting if/when it is implemented that net metering should continue to be an option at the residential and small commercial level for DG customers. A FIT may be more applicable for larger DG producers and will include the benefit of preventing grid defection of these larger customers/producers, at least during the FIT contract term.

Ben Grimstad

FITs should be considered if they encourage more DG.

Decorah Solar Field, Frank Belcastro, Jason Hall, Jean Marie Hall, Jenn Hall, Kami Ahrens, Larry A. Stone, Tim Brodersen of Moxie Solar, and William H. Ibanez

Both FITs and net metering encourage local DG development and allow for a faster transition to renewable energy.

All Points Power

An advantage of FITs is the certainty that excess power produced by a DG source will result in known cash flows, encouraging system design based on load as opposed to minimizing expense associated with electrical production. A disadvantage is consistency and scheduling complications for utilities.

Farm Energy, LLC

FITs should be offered by rate-regulated and non-rate-regulated utilities to all independently owned DG facilities in Iowa. Tariff rates should be technology specific and reflect reasonable rate of return, inflation, deferred transmission needs, reduced peak energy costs, environmental benefits, etc. Net metering should be offered as well, but there are specific advantages to FITs. DG facilities using a FIT would pay income tax on their system profits addressing concerns about lowered state revenue resulting from increased net metering installations. FITs also address aggregate meter concerns and provide a fair system for both business and residential customers.

Energy Consultants Group

Both FITs and net metering are good incentives to encourage solar growth. Based on some of the challenges and growth fluctuations seen by Germany's FIT system, net metering appears to be the more appropriate long-term choice. A study should be conducted to determine feasibility of a combination FIT and net metering system in Iowa.

John E. Carpenter
The principal advantage of a FIT is that it encourages renewable energy development. The system in place in Germany should be researched to see a working model and build a development plan. A disadvantage of FITs is that the costs may fall on other customers and the utility.

Chris Hoffman of Moxie Solar
FITs and net metering facilitate a quicker transition to renewable energy by providing financial incentive to encourage local investment in DG which will help Iowa transition to clean renewable power. The current avoided costs system discourages this growth.

Industrial Energy Applications
An advantage of FIT is that it allows for a known rate for excess energy produced by DG, without the need, expertise, and expense to negotiate a separate PPA with the local utility. A disadvantage is that the utility will have to purchase more power which will be harder to schedule, but this can be overcome with planning, customer interface, and real-time production data.

Robert Fischer
Both FIT and net metering systems provide an incentive for participation in DG. Net metering currently works very well. The advantage of a FIT would be that it allows the system owner to install a system large enough to generate more than 100 percent of their own requirements and receive a return on the surplus.

Steven Demuth
Iowa should implement a rational system of FITs that are fair to DG facilities and to Iowa's electrical utilities. Pure net metering without constraints is not sustainable if DG is widely adopted, because it does not fully reflect the costs of distributed power to the utility that is forced to acquire and distribute the power. FITs that are properly constructed can avoid this. The Board should adopt policies that strongly encourage utilities to adopt smart metering and real-time pricing of electrical usage by all consumers, and extend these policies with appropriate FITs that likewise reflect actual value of the power generated, with an allowance for utility line loss and overhead.

Wendy VanDeWalle
FITs and net metering are great DG incentives.

William J. Pardee
The community would benefit from a FIT assuring an adequate return even when energy production exceeds consumption.

6. Comment on whether you believe the Board has jurisdiction to extend the net metering requirement to coops and municipal utilities and if so, whether it should exercise such jurisdiction.

Consumer Advocate

The Board has broad general powers over the rates and services of public utilities. All public utilities, rate-regulated or not, are required to have reasonably adequate service and facilities including programs for customers to encourage the use of energy efficiency and renewable energy resources. Iowa Code § 476.8 (2013). In order to determine the Board's jurisdiction over net metering requirements to non-rate-regulated utilities, it must be determined if net metering is a permissible regulation within the Board's jurisdiction. As pointed out by the Board in defense of the net metering rule before FERC in Docket No. EL99-3-000, the net metering rule involves measurement of power, not pricing or rates. FERC agreed and rejected utility claims that every flow of power from QF generation constitutes a sale subject to PURPA requirements.

Board authorization to require non-rate-regulated utilities to interconnect customer-owned DG–was addressed in Docket No. NOI-06-4 and the ensuing rule making, Docket No. RMU-2009-0008, Electric Interconnection of DG Facilities (IUB, May 26, 2010). The Board's goal in the interconnection rule making was to facilitate the addition of DG at the distribution level. The Board indicated it would closely monitor the practical application of the rules and may propose amendments if the adopted rules are not working as intended to facilitate the interconnection of DG facilities. (Rule Making Preamble, p. 5). The Board declined to extend the application of the rules to non-rate-regulated utilities at that time indicating that it may revisit the jurisdictional issue if needed.

The overarching policy of the State is to encourage the development of AEP facilities in order to conserve our finite and expensive energy resources and to provide for their most efficient use. Iowa Code § 476.41 (2013). The Board's broad oversight authority combination with the 2005 Energy Policy Act mandate to encourage renewable energy support a finding that the Board should consider whether current policies in service territories served by non-rate-regulated utilities is sufficient to support renewable DG. If not, the Board should take action to address the policy gap.

IAEC

As noted in the Staff Memo submitted herein on May 12, 2014, the Iowa Supreme Court noted that federal law gives non-rate-regulated utilities broad discretion to implement PURPA, and concluded that a non-rate-regulated utility's decision not to offer net metering was lawful. The Court concluded that it would be erroneous for the Board to attempt to impose such a requirement. FERC stated in a 2004 Order that it has never claimed PURPA requires net metering. FERC did express its opinion that PURPA would not preempt a state legislature from requiring a utility that is otherwise unregulated to net meter. To date, neither state nor federal law currently mandates net metering for non-rate-regulated utilities.

<u>IAMU</u>
The Board does not have jurisdiction to extend the net metering requirement to municipal utilities. The Iowa Power & Light v. State Commerce Commission, 410 N.W.2d 236 (1987) recognized that the Commission (now the Board) was preempted by PURPA from imposing additional state based requirements on non–rate-regulated utilities. Amendments to PURPA adopted in The Energy Policy Act of 2005 did not change the federal preemption argument. Despite the fact that the net metering requirement was derived from state statute (sections 476.41-476.45), the court held that the requirements could not be applied to non-rate-regulated utilities, including the net metering rules derived from the statute.

<u>MRES</u>
Iowa Code §§ 476.1A and 476.1B state that the Board does not have jurisdiction over REC and municipal utility rates. Net metering and FITs bring into play the rates of REC and municipal utilities. It is integral to the local rate structure. Federal law points to a hands-off approach when it comes to non-public utility rates. Subsequent case law[37] also points out that this language not only grants FERC jurisdiction over IOU rates, but that RECs and municipal utilities are exempt from such rate jurisdiction. The state relied on similar logic in finding that RECs were not required to net meter private wind facilities in *Windway Technologies, Inc., v. Midland Power Cooperative, 696* N.W*. 2d 303 (Iowa 2005).* Under federal law, PURPA requires rates for purchases from cogeneration or DG must be just and reasonable to electric consumers and the public. Recent FERC decisions on FITs in California indicate a preference in allowing customer-owned utilities to set their own rates, rate-structures, and DG policies that would impact those rates. As to PURPA, FERC found that PURPA does not preempt states from specifying the wholesale rates for such purchases; however, those rates may not exceed the wholesale utility's avoided cost. *132 FERC 61,047 (2010).* Although this decision refers to a case involving an IOU rather than customer-owned utilities, it does show the preference for FERC to avoid rate-making, especially anything beyond PURPA's limitation of avoided cost.

<u>ELPC et al.</u>
Net metering and interconnection standards are within the limited jurisdiction the Board has over RECs and municipal utilities. The language of the Iowa Code and the differences between the language for the RECs and municipal utilities helps define the parameters of the Board's jurisdiction.

The statute is clear that RECs are not subject to rate regulation of the Board and equally clear that RECs are subject to all other regulation and enforcement activities of the Board. The other regulation and enforcement activities of the Board are open ended, but it does include some specific regulatory activities such as filing alternate energy purchase program plans with the Board and offering such programs to

[37] See CIPCO v. MISO, 561 F3d 904 (2008)(holding while FERC may review a non-public utility rate if it impacts jurisdictional transactions, in most cases, it would not review such rates); Bonneville Power Adm. v. FERC, 422 F3d 908 (2005), (holding FERC has no rate or refund jurisdiction over non-public utilities); Entergy Louisiana, Inc. v. Louisiana Public Service Commission, 123 S. Ct. 2050 (2003).

customers. Iowa law specifically applies sections 476.41 through 476.44 to encourage the development of AEP facilities to RECs.

For municipal utilities, the statute exempts them from Board regulation unless it specifically provides for regulation. The statute provides for regulation related to safety standards, discrimination against users of renewable energy resources, encouragement of AEP facilities, as set forth in sections 476.41 through 476.45 and filing alternate energy purchase program plans with the Board, and offering such programs to customers, pursuant to section 476.47.

The Board has noted that while Iowa statute does not explicitly authorize the Board to mandate net metering for DG, the authority is implicit through the Board's enforcement of PURPA and the AEP statutes, Iowa Code §§ 476.41 through 476.47. The implicit authority derived from the legislative policy and Iowa statute that allowed the Board to issue the net metering rule in the first place would allow the Board to expand the net metering rule to apply to RECs and municipal utilities.

FERC specifically addressed whether PURPA preempted a state imposed net metering requirement on a non-rate-regulated utility in a case that dealt with an Iowa REC. FERC explained:

> It is the state through its legislature that decides whether, and to what extent, a utility is regulated. Here it appears that the state legislature has attempted to regulate utility cooperatives such as the members of Central Iowa Power Cooperative by requiring utilities to offer net metering arrangements to facilities that are alternative energy facilities as defined by state law. . . . To the extent that the state legislature has required that an electric cooperative such as Midland is required to offer a net metering arrangement to a facility [], the electric cooperative is not a non regulated utility. Nothing in PURPA preempts the state from making such a decision.[38]

The Iowa Supreme Court cited the FERC Order and noted that PURPA does not preclude state regulators from requiring net metering by a utility that is not rate-regulated.[39]

Iowa law provides the Board with authority and the policy imperative to apply net metering to RECs and municipal utilities. Customers should not be deprived of the opportunity to self-generate and net meter solely because they are served by an REC or municipal utility. The Board should exercise its jurisdiction and expand net metering to cover RECs and municipal utilities.

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[38] Swecker v. Midland Power Cooperative, 105 FERC P61,238 at 62,270 (Nov. 19, 2003).
[39] Windway Technologies, Inc. v. Midland Power Cooperative, 696 N.W.2d 303, 308 n.3 (Iowa 2005) (citing Swecker v. Midland).

Sierra Club – Iowa Chapter
The Iowa Chapter believes that the Board has jurisdiction to require RECs and municipal utilities to provide net metering and FITs. The utilities will rely on two Iowa Supreme Court decisions[40] to support the position that the Board does not have jurisdiction to extend the net metering requirement; however, both cases involved rates and fees.

PURPA requires utilities to buy from and sell energy to renewable energy owners, making no distinction between regulated and non-regulated utilities. The only preemption of state regulation for non-regulated utilities is with respect to rates. The Iowa Chapter is not suggesting that the Board establish rates and fees in requiring FITs and net metering for RECs and municipal utilities but could provide that the contract be sufficient to create an incentive for a DG system.

There is no reason that all RECs and municipal utilities cannot offer net metering and FITs since some already offer these incentives. The argument that each utility has unique circumstances, and that a one size fits all policy should not be imposed on them, thus far, has not presented any supporting evidence. It seems clear that customers of one utility should not be disadvantaged and discriminated against in relation to customers of another utility. This is especially true considering a customer has no choice in his or her electricity provider. The Board certainly has the authority to prevent discrimination against customers who want to use renewable energy. See, Iowa Code § 476.21.

The RECs and municipal utilities will argue that they do not need to be regulated because they are governed by their members or a duly elected city council, respectively. Although RECs are governed by a board of directors, in many RECs the REC management hand picks the nominees for board positions, and the management discourages other nominees from running for the board. Municipal utilities are nominally governed by a board appointed by the city council, but neither the city council nor the board members are in the business of running an electric utility, so the council and board members will defer to the manager of the utility. Members of the public, as customers of the utility, therefore, have no real input in or control over the utility.

Finally, the Board could request that the legislature grant the Board authority to regulate RECs and municipal utilities. Prior to the 1986 legislation, Iowa Code §§ 476.1A and 476.1B, the Board, or its predecessor, did have that authority. These utilities would then not be classified under PURPA as non-regulated.

Ben Grimstad
The Board should extend net metering requirements to RECs and municipal utilities if the Board is deemed to have jurisdiction.

[40] Iowa Power and Light Co. v. Iowa State Commerce Comm'n., 410 N.W.2d 236 (Iowa 1987) and Office of Consumer Advocate v. IUB, 656 N.W.2d 101(Iowa 2003).

Decorah Solar Field, Frank Belcastro, Jason Hall, Jean Marie Hall, Jenn Hall, Kami Ahrens, Larry Stone, Moxie Solar, and William H. Ibanez
The Board should extend jurisdiction to implement net metering to all utilities because some utilities have net metering and the public assumes the Board has jurisdiction.

Farm Energy, LLC
Iowa should require non-rate-regulated utilities to offer net metering as numerous other states now do.

Energy Consultants Group
All utilities in Iowa should be required to provide net metering.

John B. Cook
The Board has jurisdiction to extend net metering requirements to the RECs. That jurisdiction should be exercised to require the RECs to use net metering as other utilities do.

Steven Demuth
Assuming the Board has jurisdiction, net metering rules should be applied uniformly across IOUs, RECs, and municipal utilities in a fashion that encourages distributed production, without putting utility generation and load management at risk.

Wendy VanDeWalle
The Board should require all the utilities in Iowa to net meter as other states are doing.

William J. Pardee
RECs and municipal utilities are usually monopolies within their service areas, needing regulation. It seems that the legislation creating the Board intended that all such power monopolies be regulated by the Board.

7. If you believe that net metering results in cross subsidization of DG customers by non-DG customers, how should the net metering rule be revised to reduce or eliminate such cross-subsidization?

IPL
With the current rate design, net metering may not send the right pricing signal to DG customers resulting in those customers' billing not reflecting the cost of providing service to those customers. Subsidization by the other customers or by the utility shareholders may result if DG customers do not pay their fair share of the costs. Therefore, IPL supports a more thorough cost analysis of the impact DG can have to cost-based rates.

The pricing structures were developed with the expectation that customers would take all energy service from the utility. Therefore, a reasonable approach was to bill for the service largely on the basis of kWh. With some customer deploying customer-owned generation, these pricing structures need to be re-evaluated.

IPL believes that DG customers should have their own customer class which is consistent with the Board rules for load research found in 199 IAC 35.9(2). This would reduce the chance of cross-subsidization between DG customers and non-DG customers.

A throughput rate based on kWh must recover fixed costs (sunk costs) as well as variable costs. The throughput rate structure inherently allows DG customers to avoid paying for fixed utility costs necessary to provide them service. Since these sunk costs are not negated when a customer self-generates, the recovery of these costs is shifted to other customers. The magnitude of the cost shift is dependent on operational characteristics of the DG application as well as the size of the DG system relative to the load of the DG customer.

IPL suggests that to minimize any potential cross subsidization impacts, pricing signals need to distinguish between fixed and variable costs and need to reflect the individual unbundled functional cost components (e.g., generation, transmission, distribution) to reflect actual cost incurrence. IPL believes to collect embedded costs necessary to serve the DG customer and minimize subsidies, changes to the pricing structure needs to be made. For smaller customers with one meter measuring the net flow of energy, IPL expects that two pricing mechanisms for dealing with these changes over time would be to: 1) increase fixed customer charges; and/or 2) institute demand charges. When a customer's uses and the generation are separately metered, then buy-all, sell-all pricing systems may be implemented.

MidAmerican

There is a significant amount of subsidization of DG customers by non-DG customers that take service under energy rates (no demand charges). This relates primarily to distribution service, but some transmission service as well. For instance, if these DG customers net their usage to zero kWh in a billing month they will owe the utility nothing for the distribution facilities even though they may have delivered their excess energy produced by their DG facility to the utility using the distribution facilities. The standard distribution rate will have to be paid by the non-DG customers.

By implementing demand rates and TOU energy rates for residential and small commercial DG customers, the cross-subsidization problem could possibly be eliminated. The distribution and transmission service costs could be collected in the demand charge instead of in the volumetric charges. MidAmerican already has the data from its recent electric rate case Docket No. RPU-2013-0004 that could be used to develop demand/TOU rates that are revenue-neutral to non-DG customers in the same rate class. "Additionally, these demand rates would be consistent with cost of service principles used in Docket No. RPU-2013-0004, which allocate distribution and transmission costs to customers classes based on various measures of class peak demand." This way both DG and non-DG customers are paying the costs that the utility incurs to provide them service.

MidAmerican points out that to implement demand/TOU rates for DG customers does not require a change in the net metering rules since these rules do not dictate the specific rate design to be used.

Consumer Advocate
Although the Consumer Advocate believes that the FERC ruling and conclusions on the Board's net metering rule remain sound, it might be appropriate to review this rule to make sure it is achieving the objectives while considering the utilities' interests and the non-DG interests as well as review whether the current parameters are adequate or whether other changes may be appropriate.

Another approach to consider is opening net metering benefits to more ratepayers through community aggregation for those who live in apartments or that do not have property conducive to DG installation.

There is cross-subsidization between all rate classes and between customers in different rate classes at some level. The Consumer Advocate believes that there should be caution taken before making any major change in the net metering rule unless there is a clear showing of significant cross-subsidization. It is debatable if there is significant cross-subsidization. One way to assess the existence of cross-subsidization is to see the utility's ability to collect revenues from its customers that is enough to cover its fixed costs.

The Board could adopt TOU rates to minimize cross-subsidization from non-DG customers. TOU rates properly reflect the utility's marginal cost of energy since costs vary by season and by the time of day, can help reduce usage during peak period, and can produce pricing signals that enhance resource planning and allow the utility to focus on procuring generation resources with better output efficiencies.

IAEC
The Critical Consumer Issues Forum principles are a good starting point in revising the net metering rule to reduce or eliminate cross-subsidization. The IAEC has collaborated with membership to develop a set of guiding principles for RECs to use.

MRES
Any net metering design (including setting a rate structure to avoid cross-subsidization) should be left to the municipal utility. The design depends on the system impacts, customer portfolio, and on the load portfolio. The Board does not have jurisdiction over rate structures for municipal utilities or RECs.

TASC
Iowa needs to engage in a robust cost and benefit study of net metered systems in order to adequately answer this question. A number of studies have shown net benefits

of DG to other ratepayers and based on the studies TASC believes that it is unreasonable to assume that net metering results in a cross-subsidy for non-participating ratepayers.

ELPC et al.

Assertions about cross-subsidization should not be made until an empirical analysis based on cost-of-service and value of solar can be made. There is no evidence at this time of significant customer cross-subsidization occurring as a result of net metering in Iowa. Stakeholders should be working to identify mutually beneficial regulatory models and ratemaking principles that will work better than the traditional cost-of-service model and maximize clean DG and energy efficiency.

IIEG

Costs imposed by net metering that are unrecovered for delivery and other utility services should be borne by the same customer class to which the net metering customer belongs. The costs of a residential customer's net metered facility should not be recovered by customers in the commercial or industrial rate classes.

MCA

No cross-subsidy exists. If anything, DG reduces the need for building new plants and increases the reliability of the grid.

Sierra Club – Iowa Chapter

There is no cross-subsidization. The non-DG customers benefit from net metering. Solar energy produces more power during peak load times, which should reduce demand and also reduces the need for building more generation. Additionally, local customers may have excess power that can be used locally on the transmission and distribution lines which reduces line loss and the need for peaker plants.

Energy efficiency is not accused of cross-subsidization, and renewable energy is no different than energy efficiency in that respect. Also, the large industrial customer is not being accused of being subsidized by a smaller customer when it increases peak demand and when it may be receiving a reduced rate (i.e., declining block rates) due to the large amount of energy that is being purchased.

In summary, the subsidization argument used by the utilities is a red herring to avoid supporting DG.

Winneshiek Energy District

Data and sources provide[41] support the belief that the majority of DG customers are providing net benefits to non-DG customers. Areas that increase the value of solar

[41] Provided in Mr. Johnson's initial comments. More information at the Minnesota Department of Commerce web site, https://mn.gov/commerce/energy/topics/resources/energy-legislation-initiatives/value-of-solar-tariffmethodology%20.jsp and "A Review of Solar PV Benefit and Cost Studies" by Lena Hansen and Virginia Lacy, April 2014, can be found online at http://www.rmi.org/Content/Files/eLab-DER_cost_value_Deck_130722.pdf.

include: environmental costs, distributed cost of capital, and the near- and long-term economic benefits derived from the installation and long-term ownership of renewable power.

Ben Grimstad
It is possible that in the short-term non-DG customers are subsidizing the long-term investment of the DG customers, but the good for all justifies this situation.

Birgitta Meade
Cross-subsidizing criticism of DG is a red herring. DG customers are making a short-term financial sacrifice investment to help all with the goal of reducing renewable energy costs.

Decorah Solar Field
The concept of cross-subsidization of net metering places DG customers and non-DG customers at odds with each other and stands in the way of progress toward clean energy. Cross-subsidization is not an issue when all customers are allowed to participate in virtual net metering.

All Points Power
Everyone benefits with DG. DG customers do not receive full value for avoided cost or capacity credits for the generation and transmission capacity that are no longer needed or not needed to construct. DG customers reduce fossil fuel consumption through increased production renewable energy and from higher efficiencies in CHP/WHP projects, which benefits all customers and society.

Frank Belcastro, Jason Hall, Jean Marie Hall, Jenn Hall, Kami Ahrens, Larry A. Stone, and Tim Brodersen of Moxie Solar
Net metering does result in cross-subsidization of the DG customers by non-DG customers. The costs need to be shared by DG and non-DG customers alike. There is a view that when DG has been significantly implemented that cross-subsidization will not exist and all customers will benefit from lower costs. Allowing virtual net metering allows all customers to become DG customers.

Energy Consultants Group
Energy Consultants Group is not sure why utility companies use the excuse that it is not fair for DG customers to be subsidize by non-DG customers when all benefit from the responsible actions of others. Energy Consultants Group is not aware of anyone who is against renewables and who is not willing to pay extra on their bill to ensure a clean environment. Energy Consultants Group does not think "it’s fair that fossil fuels are being subsidized along with utility companies."

Luther College
It is not clear that the current level of DG market penetration in Iowa justifies substantial concern with regard to cross-subsidization of DG customers by non-DG customers. There are a host of benefits associated with DG systems. DG systems provide grid

services and other environmental services of which they are not compensated. It is important that any net metering rule address these benefits that cut both ways in an open and transparent way.

John B. Cook
To avoid cross-subsidization utilities can charge a flat grid connection fee to cover the cost of maintaining the grid.

John E. Carpenter
Net metering or any other fair compensations system for independent energy generators does not result in cross-subsidization. Any excess energy that a PV system generates is likely consumed by neighbors. The amount paid to the utility for that energy is simply passed on to the PV system owner.

Chris Hoffman of Moxie Solar
Net metering does result in cross-subsidization of the DG customers by non-DG customers. The cost needs to be shared to encourage the DG process. Allowing virtual net metering provides an opportunity for all customers to participate. There is a view that cross-subsidization may not exist when infrastructure has been significantly changed to DG. Clean power and power provided at high demand times are benefits to all customers.

Industrial Energy Applications
Utilities can rightly argue that the recovery of fixed charges are negated for a kWh for kWh exchange at retail rates; however, DG customers do not receive capacity credits or avoided costs for generation plant or transmission capacity not needed or delayed in construction.

Others also benefit from renewable energy production and the reduction in fossil fuel consumption. Therefore, one can calculate all the layers of cross-subsidization which is very complex and difficult or assume that net metering is fair and balanced for all.

Robert Fischer
A certain amount of cross-subsidization benefits DG customers. DG facilities are based on clean, resilient and intelligent technologies that benefit all. When a new conventional power plant is built, both DG customers and non-DG customers will be expected to subsidize it through higher rates. A potential for more citizens to participate in distributed energy would be through virtual net metering.

Steve Demuth
The Board should adopt policies that clarify the degree of cross-subsidization, and phase this out over a period of time. Long-term cross-subsidization may adversely impact consumers and renters who are not in a position to invest in DG. In the short term, encouragement for establishing DG as a foundation of Iowa energy policy may justify some degree of cross-subsidization.

William H. Ibanez
Net metering does result in cross-subsidization of the DG customers by non-DG customers. The cost needs to be shared to encourage the DG process. Allowing virtual net metering provides an opportunity for all customers to participate.

William J. Pardee
Cross-subsidization is an argument created by fossil fuel interests to obstruct consumer demand for clean, renewable energy. Solar DG contributes energy to the grid during summer peak demand hours, enabling the utility and non-DG consumers to avoid buying peak power. It also enables the utility to postpone and perhaps avoid entirely the large capital costs of new generating plants, saving money for all consumers. All society is harmed by the CO_2 production from the use of fossil fuels and much of society is harmed by the measures used to extract fossil fuels. All of society benefits by reducing our dependence on fossil fuels, and therefore, these externalized costs.

8. If you believe that net metering does not take into account the benefits that DG provides to non-DG customers, how should the net metering rule be revised to account for such value?

IPL
According to IPL, net metering is not designed to measure the output at the generator which is what would provide value to the non-DG customer. Therefore, net metering does not lend itself to determining the benefits that DG may provide.

MidAmerican
For the customer classes that take service under energy only rates, DG customers are significantly over compensated for the limited benefits they provide to the non-DG customers. To resolve this issue, demand/TOU rates should be implemented (as discussed under Question 7). DG customers will avoid demand charges if they are able to reduce their monthly peak demands using their DG facilities. If there is no reduction in monthly peak demands, they did not provide benefits to the distribution or transmission systems.

Most likely DG customers provide benefits in the form of generation benefits where TOU rates would provide appropriate price signals to DG customers regarding the value of the energy and capacity their DG facilities provided.

Consumer Advocate
Net metering is not designed to recognize the benefits (i.e., societal and environmental benefits) from using renewable DG. Since most net metering programs are focused on small individual QF installations, it is "unnecessary to model the impacts in an integrated resource plan as either a significant program for load saving or as a resource cost to be avoided." In the aggregate, net metering programs sufficiently recognize the benefits and savings to the system.

It is best to use a FIT designed as a technology-specific avoided cost rate to explicitly compensate renewable energy for societal and environmental benefits.

IAEC
The IAEC is not aware of any necessary change to REC net metering policies regarding this question.

IAMU
Municipal utilities must consider fairness when determining the appropriate value and compensation for their DG customers. In consideration of long-term system support, with net metering retail rates or paid FIT incentive rates, the utility risks cost shifts to non-DG customers.

A value of solar tariff has promise as a fair method of compensation and eliminates the net metering cross-subsidization concerns. These tariffs can be expected to vary considerably, and the approach highlights the importance of local control in rate setting.

MRES
There are concrete costs associated with DG: 1) the local impacts on harmonics, voltage variations, and reliability; 2) maintaining distribution, transmission, and reactive power to provide service; 3) salaries of lineman and other employees; 4) the cost of depreciation, MISO fees, transmission equipment distribution substations, billing costs, computers, meters etc.; and 5) PPAs and investment in facilities. A subsidy is created whenever a DG resource is procured at an above market price. Concrete and stranded costs are created when a resource is added to the utility that is not part of the utility's resource planning model which are paid for by other customers.

There are useful benefits from reduced emissions; however, they are often non-measurable and, therefore, do not impact the bottom line. Germany has observed this and has significantly reduced the FIT payment amounts and are charging the DG customers for the impacts on the system. Spain is considering spreading the concrete costs to the generating customers.

"In some cases, a DG unit may offer a concrete-cost benefit, such as providing power on-peak, providing reactive power, or under the proposed EPA regulations, may offer renewable energy credits for EPA emission mandates. In such cases, there may be an advantage to spreading the costs among all customers."

TASC
There is not enough evidence to address Question 7 or Question 8. Iowa has not engaged in the accounting of the utility specific costs and benefits of net metered systems to be able to answer those questions. Therefore, there is not enough information to determine the amount of cross-subsidy or the direction the cross-subsidy flows.

There are many studies that show a net benefit to ratepayers from customer-investment in DG including the researchers in the article "Solar Power Generation in the US: Too Expensive, or a Bargain" and the staff of the Vermont Public Service Department who included the greenhouse gas compliance costs in the analysis.

A discussion of the costs and benefits of net metering in Iowa is premature and there is not enough solar PV currently interconnected in Iowa to justify the resources needed to conduct a comprehensive study of this issue. Therefore, until the market has grown large enough to warrant this kind of study, the Board should defer this discussion.

<u>ELPC et al.</u>
An objective, empirical, cost-benefit study based on cost of service and value of solar analysis is needed prior to revising the current net metering rule. In the meantime, excess production from self-generation should be credited at least equal to retail rates.

<u>Sierra Club – Iowa Chapter</u>
A solar energy customer is effectively subsidizing other customers by reducing its demand for peak generation. Each customer should pay a flat rate for basic services that are required for the utility. Customers should be charged fuel costs based on the amount of electricity used and charged for transmission and distribution based on the amount of electricity they purchase. It also makes sense to charge a customer who has DG equipment for the use of the transmission and distribution lines when they deliver power to the grid.

<u>Winneshiek Energy District</u>
Winneshiek Energy District supports further study into developing a FIT in Iowa but suggested that if a FIT is implemented then net metering should remain an option for smaller DG customers.

<u>Decorah Solar Field Frank Belcastro, Jason Hall, Jean Marie Hall, Jenn Hall, Kami Ahrens, Larry A Stone, Tim Brodersen of Moxie Solar, and William H. Ibanez</u>
Net metering provides a benefit to the non-DG customer because it promotes DG using clean power and provides power at high demand times. All customers can participate in net metering through the implementation of virtual net metering.

<u>John B. Cook</u>
DG does provide benefits to non-DG customers that can be addressed by promotion and facilitation of DG installation and maintenance by the utilities.

<u>John E. Carpenter</u>
A non-DG customer is paying the utility for electricity whether it is supplied by a PV system or a dirty old coal plant. Non-DG customers get an intangible benefit of reduced CO_2 emissions if the DG occurs in their neighborhood.

<u>Chris Hoffman of Moxie Solar</u>
The initial purpose of the current net metering rules has been to develop DG, as DG has grown, a need for virtual net metering has evolved. The rules need to be changed to allow non-DG customers to participate via virtual net metering.

<u>Industrial Energy Applications</u>
When a DG customer uses a solar system, the utility does not have to purchase as much expensive capacity during the summer peaking hours which is a benefit to the non-DG customer. The DG customer does not receive any monetary benefit for this and perhaps should. However, this benefit is difficult to quantify. Industrial Energy Applications believes the current net metering rules are sufficient.

<u>Steve Demuth</u>
Net metering should be based on metering of consumption and generation at the service entry; utilities should be permitted to impose a reasonable rate adjustment on generation to reflect costs of the utility supporting DG.

<u>William J. Pardee</u>
Net metering compensation should not be limited to 100 percent of energy used. The rate should be adjusted upward reflecting the reduction of fossil fuel costs and the value of time-of-day production.

9. For customers who currently use net metering, provide the following information:

a. Type and size of your DG facility;
b. Your electric service provider; and
c. Positive and negative experiences with net metering.

<u>ELPC et al.</u>
The Board's approach to solicit feedback from customers is a good step. Direct outreach to customers and installers will provide a more comprehensive set of responses and experiences. Customers and installers who have access to net metering have had positive experiences. Net metering is an important policy to encourage DG in Iowa. Both customers and installers have expressed that their ability to take advantage of net metering varies significantly among RECs and municipal utilities. It is difficult to understand what policy applies with some of the RECs and municipal utilities.

<u>Ben Grimstad</u>

a. 5.6 kW roof mount system in 2012 which provides 75 percent of electricity on a net metering basis.
b. IPL.
c. The process was satisfactory, labor intensive paperwork.

Craig Mosher

a. 1 kW (4 panels) PV system in January 2014 which generates almost all used power.
b. Hawkeye REC.
c. Net metering is working well. Paperwork and fees were excessive in establishing the interconnection agreement. The process needs to be streamlined in order to encourage additional DG. Mr. Mosher pays a $27 per month demand charge in addition to excess electricity to be connected to the grid.

Decorah Solar Field
Mr. Grimstad is a customer using net metering directly or indirectly with three solar facilities.

a. Facility One - 280 kW solar array leased to Luther College.
b. IPL.
c. Arrangements were all positive except for necessity to establish a lease between Decorah Solar Field and Luther College.

a. Facility Two - 3.5 kW solar array on the roof of a rental home.
b. IPL.
c. Arrangements were all positive. Mr. Grimstad would prefer to either receive a cash payment or carry over or bank excess power production.

a. Facility Three - 11 kW array partially on the roof of a building and partially ground mounted.
b. Hawkeye Tri-County REC/Dairyland Power Company.
c. Arrangements were all positive with Hawkeye Tri-County REC.

Farm Energy, LLC

a. 10 kW solar array installed in 2011.
b. Interconnected to Calhoun County REC.
c. Experience has been generally positive, but the REC did not have net metering available. This system would likely be better off with a FIT under long-term contract, or net metering that does not cash-out at year end. Year-end cash-out is unfair to solar production since solar generation is lower in the month of January.

EPo Energy
a. Type and size of DG facility:

- Tim Graber: Four 40 kW systems on farming/turkey operation.
- Paul Reed: 16.96 kW ground mount system at home farming operation.
- Porter Farms: Five 20.1 kW systems on hog buildings, two 10 kW on home farm.
- Todd Lorack: 50 kW system on hog operation.

- Darrell Egli: 10 kW on dryer operation and 67 kW system on hog/grain drying operation.
- JG4 Hog LLC: 12 kW on hog building.

b. Electric service provider:

- Tim Graber, Paul Reed, Todd Lorack, Darrell Egli, JG4 Hog LLC: all have IPL
- Porter Farms: Access Energy at 5 locations and IPL at 2 locations.

c. Positive and negative experiences with net metering:

- Tim Graber: Net Metering with banking is critical for farming operation, and in the decision to utilize solar energy to help normalize costs.
- Paul Reed: Net Metering is very important to family's decision to purchase solar systems and helps to normalize electrical costs and plan for farming operations.
- Porter Farms: The ability to bank excess power at the IPL locations has helped in the farm budget planning.
- Todd Lorack: The system is straight-forward and has had no issues understanding the process or billing.
- Darrell Egli: The net metering process is very easy and works well for operations.
- JG4 Hog LLC: Net metering was critical in the decision to purchase a solar system and net metering allows better management of contract.

<u>Energy Consultants Group</u>

a. 6.5 kW DC.
b. IPL.
c. Overall good but the process for interconnection is lengthy and complicated. The billing needs simplified.

<u>Luther College</u>

a. Luther owns three solar PV systems: 4 kW, 5 kW, and 20 kW. The college leases a 280 kW PV array to power a residential complex on campus.
b. IPL.
c. They have had positive experiences with these net metering arrangements. The net metering cap should be raised from 500 kW to 5,000 kW. The request for this ten-fold increase is tied to the college's Climate Action Plan and greenhouse gas reduction goals to generate all of the power consumed via DG that could be realized with such an increase.

Nixon Lauridsen and Rob Sand

a. 20 kW solar array.
b. Interconnected to Clarke Electric Cooperative.
c. While the experience has been positive, the primary complaint is that Clarke Electric Cooperative does not offer net metering. The price received for

electricity sold back to the grid is a small fraction of the price at which they are required to purchase it.

Industrial Energy Applications

a. Solar PV panels with nameplate rating of approximately 3 kW.
b. IPL.
c. The experience is generally positive. Because of the type of metering used by the electric service provider, it is difficult to determine at any point in time how much energy is actually being generated into the utility.

William J. Pardee

a. 10.12 kW PV array providing about 14 MWh of energy annually, or about 60 percent of the annual power consumption in an all-electric geothermal heated and cooled home.
b. Hawkeye REC's grid in late July of 2011.
c. Personal experience with net metering has been completely satisfactory.

10. Provide the advantages and disadvantages of the current net metering rules. Are there specific changes that need to occur to these rules to encourage additional DG in Iowa?

TASC

An advantage to Iowa's current net metering rules is the ability to indefinitely carry forward the allowance for net excess generation. This creates an incentive to the customer to limit the size of the DG system to only what is necessary to meet long-term on-site energy needs. TASC recommends removing size limitations from the current net metering rules to allow customers to better meet their on-site energy needs. TASC encourages the Board to expand Iowa net metering to all customers, including municipal utilities and RECs.

TASC supports consumer's rights to install self-generation through third-party arrangements. Third-party ownership of a PV system can ease the burden of necessary operations and maintenance costs and expands financing options available to customers. Third-party ownership presents an important financial option for customers who wish to install self-generation systems but are unable to make the high upfront investment. TASC encourages both the Board and the General Assembly to exhaust all actions within their authority to permit a variety of financing tools, including PPAs and leases.

ELPC et al.

ELPC et al. believe the best option is to maintain Iowa's existing net metering rules while a comprehensive study of DG costs and benefits is completed. Revisiting Iowa's net metering rules should be a data-driven process that supports Iowa's legislative policy goal to encourage AEP. In its initial comments, ELPC et al. highlighted the changes to Iowa's net metering that are recommended including expanding the cap on the size of facilities eligible for net metering, considering CHP eligibility for net metering, and expanding net metering to RECs and municipal utilities.

<u>Ben Grimstad</u>
Net metering works fine.

<u>Decorah Solar Field, Frank Belcastro, Jason Hall, Jean Marie Hall, Jenn Hall, Kami Ahrens, Larry A. Stone, Tim Brodersen of Moxie Solar, and William H. Ibanez</u>
The advantage of the current net metering rules has been to provide the initial development of DG. The disadvantage of the current net metering rules is they do not allow virtual net metering. Virtual net metering allows communities and neighborhoods to build DG facilities in a group setting, allowing for better customer pricing from the suppliers of equipment and the utility. The rules need to be changed to allow and encourage virtual net metering.

<u>EPo Energy</u>
- Tim Graber and Todd Lorack: The current net metering rules are meeting their needs.
- Paul Reed and JG4 Hog LLC: Virtual net metering would be great because at some locations there are better layouts to put the systems and these systems produce better. Virtual net metering would allow offsetting power needs at all of our locations.
- Porter Farms: IPL's net metering works well for the current operation. If the banking method would change, the value of solar energy would have to be reevaluated. For the Access locations, wholesale rate is paid for the excess power that is generated. They have only been able to make this work because the needs are primarily during the daytime and the cost of power is 30 percent less at these locations versus the IPL locations.

<u>Energy Consultants Group</u>
The current rules work ok, but virtual net metering is needed in Iowa. Countless projects have come up in which the customer was dedicated to doing solar but could not for the following reasons:

- Not enough space on roof or ground.
- Roof could not support solar load, cost prohibitive.
- Roof age or type, cost prohibitive.
- Historical structure.
- Shading issues, controlled by owner or adjoining proportions.
- Wrong orientation or don't want on the front of structure.
- Utility companies requiring extensive service upgrades to accommodate the outdated rule of adding service size plus solar size from a lack of understanding how solar works as it applies to DG.

Virtual net metering will allow people to own a plant at one location to serve many other locations and would allow a solar integrator to place plant on solar integrator farm and central monitor and care for the system. Energy Consultants Group's studies have shown that lower cost of ownership to this and reduce the burden on infrastructure on the utility side.

Atwood Electric
In general, REC customers do not have a net metering or kWh banking option that is available to IOU customers. DG is good for the Iowa economy, can be very good for the grid stability, reduces system losses, expedited start to finish construction times, etc. REC customers would like to have the same opportunities.

- Duane Atwood, Dennis Hammes, and Doug Flynn would like to put solar on their properties but the REC does not have a net metering available.
- Ryan Vogel, Joe Eiben, and Jeff Andeway would like to install solar panels on the hog site just outside Martinsburg but found that T.I.P. REC does not offer net metering, so it does not make sense to install the system.
- John Waltzing wanted to install solar panels on property but learned that it would not make sense because Prairie Energy Coop in Garner does not offer net metering. The REC gets to benefit from locally generated power, but the consumers do not.

William J. Pardee
Mr. Pardee understands that if he expands his DG system so that electric energy production exceeds 100 percent of his annual energy consumption, the compensation would drop sharply to the avoided cost. That calculation does not accurately reflect the avoided cost to society by:

- Reducing the need for very expensive peak load power purchases.
- Reducing the need for capital to expand expensive fossil fuel plants.
- Reducing the enormous and increasing externalized costs of extraction, transportation, and consumption of fossil fuel.
- The value of reduced CO_2 production.

The compensation rules could use time of day metering to reflect the value of peak load power and include compensation for the tons of CO_2 avoided and account for the general societal benefits.

General Net Metering Comments

IPL
The financial impacts of net metering for net metering customers, non-net metering customers, where one meter measures the net inflow or outflow of power, can only be fully understood when one also knows the rate design against which the consumption or use is applied. There cannot be an effective net metering discussion unless there is also a clear understanding of the rate design that is inherently attached to it both today

and in the future. The impact of DG under net metering is a function of both the metering/billing configuration and rate design.

IPL assumed that net metering would be applied against its rate design under existing tariffs, which includes relatively high levels of fixed cost recoveries through usage (kWh) charges. This promotional incentive paid for (renewable) DG via net metering resulted in an inherent price paid that is likely different than the costs otherwise incurred by the utility to supply power to customers. A net metering approach provides a payment for DG that compensates the DG customer for costs that are likely not totally offset by DG itself for example, transmission, distribution and back-up power supply costs. The Board's current rules on net metering were the result of a negotiated settlement that, resolved a potential contested case about net metering. Net metering was not designed to define the value of a particular DG resource, nor was the economic impacts at meaningful penetration levels considered. It was not created as an efficient long-term pricing system assuming a broader deployment of DG. Something other than the existing net metering policy is likely needed as a long-term solution, and these pricing systems are just now being developed in the industry.

IPL does not believe it is prudent to expand net metering beyond its current use in Iowa unless a way is found to address its existing inequities as an economic pricing approach. IPL believes that DG can be more equitably promoted through a cost-based, rather than a net metering, approach.

Net metering provides a payment for DG at the retail rate paid by the customer. The average rate paid by the residential customer in today's system covers a number of bundled services, as shown in the hypothetical example below.

Cost category	% of bill	cents / kWh
Generation costs (non-fuel)	32%	4.48
Generation costs (fuel / purchased power)	17%	2.38
Transmission	19%	2.66
Distribution	14%	1.96
Distribution – Customer Costs	18%	2.52
Total	**100%**	**14.00**

While these are hypothetical data, they are directionally consistent with the costs on IPL's system. Clearly, the fuel/purchased power costs (2.38 cents per kWh) are costs that are avoided by generation behind the meter in a net metering scenario. All other costs shown above are arguably not avoided (due to the behind the meter generation) to some degree:

- Utility-owned generation is still needed when the customer's generation is not operating;
- Transmission and distribution systems are still needed to deliver that power to ensure continuous reliability; and

- Direct customer costs are also still needed to connect the customer to the integrated system (although some of these costs are recovered through the customer charge).

Therefore, the under-recovery of these remaining fixed costs (14.00 cents less 2.38 cents) is the potential subsidy participating customers receive when net metering credits the full retail rate, recognizing that a variety of factors may cause that potential subsidy to be reduced.

Given the current potential for increasing penetration of DG installations in the marketplace and the decreasing costs of DG technologies, net metering (with current rate design) should no longer be the standard ratemaking approach. The Board should consider how to develop cost-based pricing systems that deliver the best long-term value of DG for customers in total.

MidAmerican

There are underlying legal issues surrounding net metering in Iowa that should be considered before making any changes to net metering. The authority to set rates, terms, and conditions of service for wholesale power sales is not delegated to the Board. In *MidAmerican Energy Co.*, 94 FERC ¶ 61,340 (2001), FERC clearly stated that net sales from a QF must be made at avoided cost rates:

> When there is a net sale to a utility, and the individual's generation is a QF, that net sale must be at an avoided cost rate consistent with PURPA and our regulations. 94 FERC ¶ 61,340 (2001) at ¶ 4.

Most of the policy options the Board wants commenters to address would extend net metering beyond Rate NM of QFs beyond the parameters of the current one customer/one site approach of Rate NM and may be subject to the jurisdiction of FERC over wholesale power before they can be implemented in Iowa.

In addition to potential federal jurisdiction issues, the Board should consider the impact of assigned exclusive electric service territory on electric utility service in Iowa. Certain options addressed above could compromise this system. The assignment of service territory applies to all elements of electric power and energy sold in Iowa –generation, transmission and distribution – so retail wheeling is not authorized in Iowa. To the extent any extension of net metering would involve a utility distribution system, such as virtual net metering or aggregation of front-of-the-meter load, it may not be consistent with Iowa's system of coordinated, cost-effective electric service.

As a matter of policy, the Board should, determine that DG rates should not involve subsidization of DG customers by other customers or by the utility. Net metering makes the assumption that the value of every kWh of net metered production delivered to the grid is always equal to the rate block that the net metered customer avoids paying for bundled electric service provided by the utility. There is no nexus between the value to the grid of a kWh of unscheduled DG energy and the revenue requirement associated with the utility's depreciated embedded investments, costs of operation and maintenance, depreciation expenses, and costs of generation services dispatched by MISO. The number of customers and amount of net metering resources has had significant growth since FERC indicated in *MidAmerican Energy Co.*, 94 FERC ¶ 61,340 (2001) that it would not exert jurisdiction over individual homeowners and farmers who net metered.

MidAmerican's comments on each of the options set forth in this question address the underlying policy implications and are not intended to suggest each option is legally permitted under state and federal regulatory frameworks.

<u>IAEC</u>
The IAEC cautions the use of a one size fits all approach to net metering. Any evaluation of an appropriate net metering policy must take into account the existing rate structure and potential concerns to recover costs. To the extent that some subsidization through rate structure is deemed appropriate, the Board must consider the differences in: assigned electric service areas; types of customers served; size of electric utilities; time period of peaking and other parameters.

Summary of Responses to Interconnection Questions

1. Do the current interconnection rules ensure that DG installations are safe for customers and utility employees? If not, what specific changes are needed to ensure safe installation and operation of DG equipment? Include specific examples of safety problems, if any, and customer or utility behaviors that may compromise safety.

<u>IPL</u>
The current interconnection rules allow for safe DG installations from an electric utility standpoint.

<u>MidAmerican</u>
MidAmerican believes the current interconnection rules ensure that DG installations are safe for customers and utility employees, when followed. There may be a need for periodic inspections after installation to ensure proper upkeep and maintenance.

<u>Consumer Advocate</u>
Current interconnection rules ensure safety. The Consumer Advocate is unaware of any situations involving safety issues when current rules are followed.

<u>IAEC</u>
The Board’s adoption of various codes and standards (specifically the Standard for Interconnecting Distributed Resources with Electric Power Systems, American National Standards Institute (ANSI)/Institute of Electrical and Electronics Engineers (IEEE) Standard 1547-2003, the Iowa Electrical Safety Code, and the National Electrical Code,

ANSI/National Fire Protection Association (NFPA) 70-2011) provide a foundation for safe interconnections of DG. There are regulations related to certain DG facilities in IAC chapters 15 and 45 that require an inspection of the DG installation.

The State of Iowa has not adopted the 2012 International Fire Code that has provisions related to solar PV power and marking requirements, main disconnect requirements, access, pathways, and ventilation. The IAEC and member cooperatives have developed model policies to comply with the applicable provisions of the regulations. The policies are included as part of an REC's tariff on file with the Board.

The local regulations and policies do not ensure all interconnections are safe and collaborative work needs to continue between the utility, local and state inspectors, customers, installers and other invested parties. The IAEC is aware of instances where the REC was not notified of an installation until after the DG system was operating. The IAEC has been working with member cooperatives, the Iowa Energy Center, Iowa Farm Bureau Federation and others to educate member-owners about DG and interconnection. The IAEC does not feel that the adoption of more regulations is necessary but suggests that additional information be added to the Board's Web site or provide information to the public regarding safely interconnected DG.

<u>IAMU</u>
The IAMU supports required training and certification for DG installers and electrical inspectors and developing fact sheets for customers of any utility listing the minimum certification requirements for potential DG installers.

<u>MRES</u>
The state has adequate safety rules under 199 IAC 15.1 but there is an issue with enforcement of those rules. State rules need to mandate that qualified personnel are doing electric work and inspections with consequences for failure to abide by those mandates. MRES has seen poor wiring, poorly interconnected facilities, and missing manual disconnect mechanisms. Iowa Code § 476.6A requires an owner to give the distribution utility at least 30 day notice of the construction or installation of the generating unit, but there is no penalty for failure to give the notice. There are no qualification or work standard requirements for personnel working on the units and installation. There should be more accountability for safety with regard to the distribution grid.

<u>ELPC et al.</u>
Iowa's current interconnection standards in 199 IAC chapter 45 are working well. In November 2013, FERC updated its Small Generator Interconnection Procedures (SGIP) to better accommodate higher levels of DG penetration [42] and several states have also updated their standards or are in the process of updating them. Iowa should also update its standards to be consistent with FERC's updated SGIP in anticipation of higher penetrations. In this way, Iowa will be able to avoid problems that have occurred

[42] Order No. 792, Small Generator Interconnection Agreements and Procedures, 145 F.E.R.C. ¶ 61,159 (2013).

in other states and take advantage of the solutions already developed elsewhere and adopted by FERC.

Specifically, ELPC et al. recommend considering the following changes to Iowa's procedures:

- Include a pre-application report.[43] Allow a potential applicant to submit a written request and obtain, for a fee, pre-specified data related to a proposed project at a specific site. A structured pre-application report can reduce unnecessary interconnection applications by providing information about system conditions at a proposed point of interconnection.

- Modify Level 2 eligibility requirements.[44] FERC adopted a more sophisticated method for determining eligibility for its Fast Track review, which relies on a combination of facility size, distribution line voltage, and distance from the substation.

- Incorporate a clearer Supplemental Review process.[45] Iowa permits additional review if a facility fails to meet one or more of the Level 2 screens,[46] but this process is relatively vague and open-ended. A clear, more transparent Supplemental Review process can enable efficient interconnections at higher penetrations and still ensure system protection. Specifically, it can maintain a fast process for projects in low penetration areas, but can provide utilities with sufficient time to conduct additional analysis in higher penetration cases where full study is not necessary. A Supplemental Review process similar to the one in the FERC SGIP has been adopted in Ohio and is under consideration in Illinois and North Carolina.

In addition to these changes based on the FERC SGIP, ELPC et al. recommend some additional changes based on IREC's Model Interconnection Procedures, which reflect best practices nationally.

- Increase the Level 1 review threshold to 25 kW.[47] As the volume of residential and small commercial interconnection increases, it makes sense to ensure continued administrative ease in the interconnection of these generators.

- Modify the "no construction screen" in Levels 1 and 2.[48] Iowa prohibits generating facilities that pass other technical screens for expedited

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[43] FERC SGIP § 1.2; see also IREC Model Interconnection Procedures § II; NREL, Updating Small Generator Interconnection Procedures for New Market Conditions 12-15 (Dec. 2012), available at www.nrel.gov/docs/fy13osti/56790.pdf [hereinafter NREL Interconnection Report].
[44] FERC SGIP § 2.1; see also IREC Model Interconnection Procedures § III(B)(2)(a).
[45] FERC SGIP § 2.4; see also IREC Model Interconnection Procedures § III(D).
[46] 199 IAC § 45.9(6).
[47] IREC Model Interconnection Procedures § III(A); see also NREL Interconnection Report at15-16.
[48] IREC Model Interconnection Procedures §§ III(A)(5), III(B)(5); see also NREL Interconnection Report at 28-29.

interconnection review from obtaining an interconnection agreement if they require construction of any facilities by the utility on its system.[49] This "no construction screen" results in unnecessary studies and can be particularly problematic for generating systems wishing to interconnect in locations without onsite load.

- Eliminate the Feasibility Study.[50] Many states have moved to a one- or two-study process in the interest of efficiency and cost-effectiveness. Much of the crucial detail of interest to generators and utilities does not come until the later studies.

- Do not allow the utility to require an external disconnect switch for an inverter-based facility.[51] It is well established that inverter-based systems, such as solar PV systems, can be safely and effectively connected to the grid without an external disconnect switch.[52] An external disconnect switch fails to provide the fail safe protection that is its justification, is redundant if employed on systems with Underwriters Laboratories (UL) and IEEE-listed inverters, and adds unnecessary cost to a PV system. Alternatively, if the Board chooses to continue to allow utilities to require an external disconnect switch, the Board might consider requiring a utility to reimburse applicants for the cost of the switch.

- Require utilities to dedicate a webpage to interconnection.[53] This page should include the utility's interconnection procedures, applications, agreements and other attachments in an electronically searchable format, and the utility's point of contact for submission of interconnection applications, including email and phone number.

- Require utilities to allow online applications and electronic signatures to be used for interconnection applications.[54] Online applications are efficient because they shorten the time it would take for a utility to process a complete interconnection request, identify application deficiencies and create an electronic trail that increases accountability. Electronic signatures are generally recognized in commercial activities, and 47 states have adopted the substance of the Uniform Electronic Transaction Act, a model act developed by the National Conference of Commissioners on Uniform State Laws.

[49] 199 IAC §§ 45.8(1)(e), 45.9(1)(j).
[50] See NREL Interconnection Report at 31-34.
[51] IREC Model Interconnection Procedures § IV(D)(5).
[52] See Michael T. Sheehan, P.E., IREC, Utility External Disconnect Switch: Practical, Legal, and Technical Reasons to Eliminate the Requirements (Solar ABCs) (Sept. 2008), available at www.solarabcs.org/about/publications/reports/ued/pdfs/ABCS-05_studyreport.pdf; M.H. Coddington et al., NREL, Utility-Interconnected PV Systems: Evaluating the Rationale for the Utility-Accessible External Disconnect Switch (Jan. 2008), available at http://www.nrel.gov/docs/fy08osti/42675.pdf.
[53] IREC Model Interconnection Procedures § IV(A)(2).
[54] IREC Model Interconnection Procedures § IV(A)(2).

MCA
MCA believes that current regulations ensure safety for both customers and utility employees.

Winneshiek Energy District
Regarding issues of safety, costs, and process, IREC's Model Interconnection Procedures is recommended.[55] Recent interconnection proceedings in California's Rule 21[56] are especially relevant regarding the capacity of smart inverters to significantly increase the ability of distribution circuits to accommodate DG.

All Points Power
Current interconnection rules, standards and codes ensure safe and reliable operation of DG systems. In addition, the requirement for a licensed electrician and the local utility to sign-off prior to energizing new systems ensures safe and reliable operation of systems.

Energy Consultants Group
Current interconnection rules ensure DG installations are safe for customers and utility employees. To ensure the safest operation of emergency response personnel and utility workers, Iowa solar systems should require new standards of rapid shut down.

Luther College
Luther College believes that the current interconnection rules assure safety for customers and utility employees. The wind turbine project, for example, required the installation of an expensive circuit breaker so that power is not fed back onto IPL's distribution grid in the event of a power outage.

Industrial Energy Applications
Current interconnection rules requiring sign-off by a licensed electrician and inspection by the local utility are adequate for safety to both the customer and utility personnel. There are concerns that interconnection agreement requirements are not appropriate for smaller DG installations because they are cumbersome time consuming, and may be a hindrance to DG growth in Iowa.

Steve Demuth
Current rules are sufficient.

IBEW
Utility workers are trained to deal with energy sources that they are aware of. There is concern for the utility worker's safety if the interconnection is not properly performed or the utility worker is unaware of the DG facility's existence. An additional concern is how the established practices and rules are implemented, monitored, and enforced.

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[55] Available at http://www.irecusa.org/publications/ under the "regulatory" heading.
[56] See http://www.cpuc.ca.gov/PUC/energy/Procurement/LTPP/rule21.htm.

Clarity is needed on the following questions to ensure system reliability and safety due to interconnection of DG resources.

- Where are inspectors employed and how are they qualified?

- Does the utility have the opportunity to inspect a DG before the final switch is turned on?

- Will there be significant fines for DG installations without the proper processes?

- Will there be stiffer fines and civil charges for improperly processed DG installations that result in someone's injury or death?

2. Is there an issue with customer DG installations occurring without the knowledge of the utility? If so, what is the magnitude of this problem, and how should it be addressed?

<u>IPL</u>
IPL is aware of a few customers who have completed DG installation without the utility's knowledge but is unable to speak to the magnitude or extent of the problem. When this situation occurs, 199 IAC chapter 45 requirements are not being followed and the system is operated without the utility's final approval. Circumstances resulting from this situation include production being recorded as consumption and one occurrence of a blown transformer due to voltage fluctuations. IPL supports training and certification of DG installers to remedy this problem.

In addition, IPL's sister utility Wisconsin Power and Light Company (WPL) utilizes advanced metering infrastructure. When DG is installed without WPL's knowledge a metering alarm or a customer call due to energy outflow is recorded as consumption provides WPL an opportunity to conduct an inquiry. Through this process WPL is able to work with customers to resolve the issue.

<u>MidAmerican</u>
MidAmerican is aware of instances where DG installations have occurred without the utility's knowledge that could result in safety, asset protection, or reliability issues. Increased public awareness of Iowa's law requiring host utility notification of installation would benefit all involved. It also should be noted that the interconnection rule's process may exceed the 30-day advance notice and it may be more beneficial to have a longer notice.

<u>Consumer Advocate</u>
The Consumer Advocate is not aware of specific issues with DG installations occurring without the knowledge of the Iowa utility or related problems.

IAEC
The IAEC is aware of instances where DG connections have occurred without the notification of the utility but is unable to determine the magnitude of the problem. Certification of installers comparable to the certification of competitive natural gas suppliers may be a starting point in establishing some consumer protection in this area.

IAMU
There have been a few reports from municipal utilities of DG installations occurring without following utility procedures and approval processes but these occurrences have been resolved and the IAMU does not see significant issues.

MRES
MRES is aware of one situation of a customer installing a DG facility without notifying the utility but it is difficult to know if there are more. The Board should consider financial penalties or even prohibiting on interconnection for such installations as current rules have no firm enforcement provisions or consequences for such actions.

ELPC et al.
ELPC et al. is not aware of DG installations occurring without the utility's knowledge. If this is occurring the state should investigate and enforce the rules already in existence.

IBEW
Utilities are discovering DG utilities that have been unknowingly connected. Something needs to be done to prevent this and putting lives of utility workers and the public at risk.

MCA
MCA is currently unaware of any unknown interconnections by DG systems in Iowa

Energy Consultants Group
Energy Consultants Group does not have knowledge of DG installations occurring without the knowledge of the utility, however there may be "preppers" looking to install systems on the down-low.

John B. Cook
DG installations should occur with the knowledge and with support from the utility.

William J. Pardee
DG installation without utility knowledge may occur occasionally. Ensuring that only licensed installers can purchase inverters will address this issue.

3. Are rule changes necessary to ensure system reliability is not harmed due to interconnection of DG resources? Provide specific examples of reliability effects from the interconnection of DG.

IPL

IPL has experienced reliability effects from oversized solar and wind installations. These installations create problems where the DG equipment was sized for 100 percent of the total annual energy needs instead of sizing to 50-80 percent of the energy load. Monthly, the majority of customers operate within 50-80 percent of their load (or less).

During lighter times of year, the customer is over-producing enough energy to bank through the higher usage times. On some systems, this creates over-voltage to the utility and to the customer. The over-voltage could affect the customer-owned system and possibly affect other customers during certain loading and feeder configurations.

Requiring installers to complete proper voltage-affect analysis on the DG facility to guarantee proper operation of the system during light load to full load is critical. There are an increasing number of instances where the customer is generating 126-130V at the point of interconnection and potentially even to the point of common coupling. During times of excess DG production this can create voltage rise on IPL's distribution system. As a large rural utility, this is becoming an issue as existing feeders are operated to support voltage from a single source. Correcting voltage support problems requires significant financial investments to ensure reliability. Installing larger conductors than necessary on both the utility's and customer's side may be necessary in certain installations. There is less impact on short urban feeders which tend to have better voltage support. Another option to counter the voltage fluctuations that occur with DG is to require the installation of smart inverters on new installations to ensure smooth integration onto the electric grid. This technology allows for effective integration of these installations by providing the necessary voltage support for these intermittent resources, which can cause power quality problems and reliability impacts because of fluctuations in their generation output. The smart inverters help ensure the integrity, safety and reliability of the system.

Large DG customers (500 kW or greater) interconnecting with IPL's distribution system are creating different issues by preventing or hampering other generation from being able to interconnect to the system. For example, a large DG unit may preclude a small solar panel from being able to interconnect as the solar customer may be limited greatly due to backflow onto the transmission system. IPL is finding the larger units require use of the entire load on the distribution system. Another impact related to larger DG units is wear and tear to the IPL system. IPL's substation transformer load tap changers are operating more to assist with voltage regulation due to large DG customers on the distribution line. At this time, IPL has not fully evaluated or reached a conclusion on what, if any, reliability impacts this may present or what cost increase this may bring about in its maintenance program.

<u>MidAmerican</u>
The interconnection rules provide reasonable methods to ensure reliability in most DG installation scenarios. A scenario not explicitly covered in the interconnection rules is where an entire development is promoted or required to have renewable generation. This scenario usually occurs with solar in new developments and exists in our service territory. Existing rules do not enable review of such developments and planned DG as a whole. A review process would benefit customers and the utility to see if such a development will cause the need for system upgrades where currently the need can be discovered when the last customer in the development requests interconnection and is assigned the upgrade cost.

Existing rules allow for cost recovery, it should be recognized that there are generation thresholds that result in required upgrades at the secondary transformer, feeder tap, and further upstream system to accommodate generation. This is especially true in developments where the majority of customers have DG. As interconnection requests increase in volume and size, the likelihood of the next interconnection request triggering a required upgrade increases. Potential reliability effects from interconnection are:

- Reverse power flow from DG to the distribution system may damage equipment not designed for flow in this direction;

- Service restoration to customers during outages may take longer as crews need to assure that DG on an affected circuit are visibly disconnected;

- High voltages during periods of light load occurring near DG and nearby customers;

- Voltage step changes occurring when the DG is cycling output, such as cloud cover for solar generators;

- Circuit islanding if the sum of the DG exceeds the load on the circuit; and

- Strict settings on DG exacerbating the under frequency problem during periods of under frequency.

<u>Consumer Advocate</u>
The Consumer Advocate is not aware of circumstances in Iowa indicating a rule change is necessary to ensure system reliability is not harmed due to interconnection of DG.

<u>IAEC</u>
At this time, the IAEC is not aware of necessary rule changes to ensure system reliability due to interconnection of DG resources. The IAEC is aware of situations

where the Level I eligibility criteria in 199 IAC chapter 45[57] is met but eligibility is not accepted.

IAMU
Municipal utilities' local control and system planning processes enable them to respond with flexibility should significant interconnections of DG require more detailed distribution reliability analysis. Reliability effects may include blinks in power on system circuits and connection of DG to dead feeders.

MRES
Interconnection rules should reflect the best practices set forth by the IEEE and/or other relevant sources. Municipal utilities should be able to set forth additional safety standards as deemed appropriate by the unique needs and possible impacts to their distribution system. There is a need for enforcement of rules and consequences for failure to comply. With generation products sold on-line and through other less reputable entities, the rules are needed to protect both the utility and utility system as well as the homeowner.

ELPC et al.
ELPC et al. is not aware of any specific reliability effects from systems that have been installed appropriately pursuant to Iowa's interconnection standards.

The technical screens used in the expedited review levels (Levels 1 through 3) explicitly provide protection against reliability impacts of systems permitted expedited treatment.[58] All of these screens are conservative by design. For example, the penetration screen (15 percent of peak load) used in both Levels 1 and 2 is intended to ensure that the combined DG on a line section, including the interconnection applicant, is well less than the minimum load (15 percent of peak load is approximately 50 percent of minimum load), thereby ensuring that the risk of unintentional islanding, voltage deviations, and other potentially negative impacts is effectively eliminated.[59]

If a project fails any of the screens, then it must undergo a thorough study process (Level 4) during which the utility has the opportunity to ensure that the reliability of the system is not affected by the proposed interconnection. [60] For example, the impact study explicitly "evaluates the impact of the proposed interconnection on both the safety and reliability of the utility's electric distribution system."[61]

[57] "For interconnection of a proposed DG facility to a radial distribution circuit, the total DG connected to the distribution circuit, including the proposed DG facility, may not exceed 15 percent of the maximum load normally supplied by the distribution circuit."
[58] See 199 IAC §§ 45.8 – 45.10.
[59] 199 IAC §§ 45.8(1)(a), 45.9(1)(a); see also Michael Coddington et al., Updating Technical Screens for PV Interconnection 1-2 (Aug. 2012), available at www.nrel.gov/docs/fy12osti/54103.pdf (explaining rationale behind 15 percent screen).
[60] See 199 IAC § 45.11.
[61] 199 IAC § 45.11(6).

All Points Power
Current interconnection rules adequately protect system reliability. Most DG systems are small compared to the grid to which they are interconnected. Issues would likely be isolated to the local distribution level by either the DG or the utility system's protective relaying.

Energy Consultants Group
Energy Consultants Group has not heard of renewable systems affecting grid reliability, considering the requirement for inverters to shut down when grid power is not present. Keeping solar simple benefits the customer, anything adding to customer costs would add to the complexity.

Luther College
If there is a 15 percent rule regarding maximum DG input to a feeder line, it should be revisited. Based on recent conversations IPL's regional representative and the Decorah City Council, it is understood that there is a state rule that DG capacity cannot constitute more than 15 percent of a feeder line's maximum capacity. It is also understood that the feeder line serving Luther College and its neighbors has exceeded the limit leading to higher level and higher expense interconnection studies for some neighbors.

Industrial Energy Applications
Industrial Energy Applications does not have knowledge of documented system reliability impacts caused by DG in Iowa. DG electrical output and sources are small compared to utility distribution capacity and it is likely that any impact would be local and isolated.

4. Considering the benefits that accrue to the system from DG, what is the correct price to charge for interconnection of DG systems? Should this price be technology dependent?

IPL
IPL is not clear what benefits are being referenced in the question. Generally speaking, costs should be borne by the interconnecting customer based on the direct costs of interconnection and should not be technology dependent.

Current pricing and fees associated with Level 3-4 DG systems should continue as structured today. Utilities collect an upfront application fee to recover costs associated with the interconnection of the DG. This structure protects other customers from subsidizing the DG installation.

Based on today's application fees, other customers are subsidizing completed Level 1 and 2 DG installations and IPL recommends the Board increase the flat fee for these applications. Level 1 DG systems require a flat $50 application fee and Level 2 DG systems require a flat $100 application fee plus $1 per kVA. The fees cover the average administrative time to process the applications, but not the average time for an engineer to review the DG system and complete a witness test. The current procedures do allow the witness test to be waived by the utility. IPL believes that the price should be based on the average cost to process the application from acceptance to delivery of the certificate of completion, including the cost of an engineering review and witness test. IPL estimates this cost at $250.

MidAmerican
Benefits accruing to the system from DG are limited. MidAmerican believes that all DG customers benefit from an interconnected generation, transmission, and distribution system and should pay the full cost to interconnect and use the system regardless of the DG technology.

Consumer Advocate
The price for interconnection should be based on actual costs to interconnect.

IAEC
The Public Utilities Regulatory Policy Act of 1978 (PURPA) defines interconnection costs as follows:

> Interconnection costs means the reasonable costs of connection, switching, metering, transmission, distribution, safety provisions and administrative costs incurred by the electric utility directly related to the installation and maintenance of the physical facilities necessary to permit interconnected operations with a qualifying facility, to the extent such costs are in excess of the corresponding costs which the electric utility would have incurred if it had not engaged in interconnected operations, but instead generated an equivalent amount of electric energy itself or purchased an equivalent amount of electric energy or capacity from other sources. Interconnection costs do not include any costs included in the calculation of avoided costs.

In order to ensure fairness, PURPA provides that the DG owner may be charged the interconnection costs. The Board should take care in removing these consumer protections that were put in place without a replacement of such. There are jurisdictional limitations in this regard and the IAEC believes the definition is flexible enough to allow for separate costs by technology to the extent they differ or the same across technologies if they are the same.

IAMU
Any benefit that accrues to the system should be paid through the DG rate. The cost of interconnection should be treated separately. The correct price is a price that keeps the utility and the utility’s customers whole without causing cost shifts. Small residential DG systems have little impact and require minimal interconnection effort. Large DG systems developed to significantly exceed a customer’s onsite energy needs may need to undertake studies and possibly upgrade infrastructure and metering.

MRES
The benefits of DG and the type of technology are irrelevant to interconnection fees. Costs of interconnection will vary from community to community and municipal utilities should set their own rates based on cost. Standardized interconnection or inspection fees are not appropriate. Cities have differing costs for interconnection work and must be able to recoup the costs from the generation owner. MRES has created an interconnection manual that utility members may adopt. In order to maintain utility worker safety and system integrity, municipal utilities and their governing bodies should have the ability to adopt their own standards on interconnection.

ELPC et al.
Changes to Iowa's interconnection fees should be based on data demonstrating the utility costs and that the utility has implemented modern practices to minimize interconnection costs. Utilities in jurisdictions with higher DG penetrations are moving to web-based interconnection applications, further streamlining the process and lowering the interconnection review costs.[62] Interconnection standards are generally technology neutral and not intended to compensate DG for the benefits created for the grid.

ESA
Interconnection prices should be based on standardized interconnection studies that evaluate system impacts. Prices should not be technology-specific.

MCA
The interconnection agreement is not the proper place to address accrued DG benefits. It should cover the cost of the actual interconnection, a one-time event. If DG systems are shown to create benefits to the utility and grid at-large, the benefits would occur continuously for what could be a long period of time. The monetization of continuous benefits in a one-time payment could underprice accrued DG benefits. MCA does not believe interconnection prices should be technology dependent to any greater degree than they already are.

Sierra Club - Iowa Chapter
The cost of interconnection for DG should be nominal and encourage interconnection.

Decorah Solar Field and Frank Belcastro
There is a greater cost to connect an individual DG system than to add generating capacity to a community DG. If virtual net metering is utilized at a community DG, it may be possible not to have an interconnection price.

[62] See, e.g., Commonwealth Edison (Illinois) Online Interconnection and Net Metering home page available at https://interconnect.comed.com/ComEd/Home/?ReturnUrl=/&_ga=1.263272970.783641903.1403587069 (last visited June 24, 2014).

<u>All Points Power</u>
The cost to process an Interconnection Agreement and the costs associated with the physical installation of the DG system are two separate issues. DG customers should not be charged fixed engineering and administrative fees associated with processing an Interconnection Agreement since there is no incremental cost to the utility for providing this service.

In terms of the physical interconnection, the costs to ensure reliability and safety within the utility transmission and distribution system are already paid by the DG customer as stipulated in the Interconnection agreement. If the utility must provide equipment within its systems to facilitate interconnection, then the labor and expenses could be paid by the DG customer. The cost of interconnection should not be technology dependent.

<u>Energy Consultants Group</u>
The current monthly service fee for the meter fee seems plenty.

<u>Jason Hall, Jean Marie Hall, Jenn Hall, Kami Ahrens, Larry Stone, Tim Brodersen of Moxie Solar, and William H. Ibanez</u>
There should not be a charge for interconnection. If there is a charge it should be enough to cover administration by the utility. Most utilities in Iowa are already receiving amounts to cover this cost.

<u>Luther College</u>
Luther College does not feel well-qualified to advise the correct price to charge for interconnection systems. It is worth pointing out that a 1,500 kW wind generator will likely produce eight times as much power as a 1,500 kW solar PV array. It might make sense to charge more to interconnect a similarly sized wind project than a PV project because the cost will be more prohibitive for the PV developer than the wind developer.

<u>John B. Cook</u>
The charge for DG interconnection should be minimal to encourage DG.

<u>Chris Hoffman of Moxie Solar</u>
The correct interconnection price should be zero or enough to cover administration by the utility.

<u>Industrial Energy Applications</u>
It is not appropriate for a 300 MW project and a 3 kW project to have the same interconnect cost structure. Utilities do not have incremental costs for negotiating an interconnect agreement, so DG customers should not pay fees associated with obtaining an agreement. With respect to the physical interconnection, charges should be based on labor and material expenses incurred by the utility to facilitate the interconnection. The fee structure for DG Interconnection should not depend on technology.

<u>William J. Pardee</u>
It is fair to charge for the costs of inspection with regards to charging for interconnection of DG systems.

5. How should distribution or transmission system upgrade costs associated with DG installation be properly allocated? Are there specific benefits that all customers (DG-owning and non-DG owning) receive from DG required transmission or distribution upgrades and, if so, what are the specific benefits?

<u>IPL</u>
System upgrade costs associated with DG installation should be situation dependent. Transmission upgrade costs will be incorporated into the MISO transmission planning process. Any upgrades to the system borne by the DG owner that provide benefits to others should be reflected in the price paid by the DG owner.

<u>MidAmerican</u>
Under traditional cost of service ratemaking, allocation of system upgrade costs to DG customers requires that DG customers be set aside as a separate customer class within cost of service and the upgrade costs be separately identifiable. Until there are enough DG customers on the system, an accurate and stable load shape for a DG customer cannot be determined in order to separate this class of customer to determine cost of service.

Although transmission and general distribution upgrades may be caused by DG customers, it is likely that they provide benefits to all customers. DG related distribution and system upgrade costs should be treated the same way that all other distribution and transmission costs are treated for the purposes of cost allocation and rate design.

<u>Consumer Advocate</u>
Generally costs associated with DG installation should be assigned to the interconnecting generator that causes the costs. If broader enhancements are undertaken, it is appropriate to apportion a lesser amount of the costs to the interconnecting DG. Allocation of required transmission upgrades costs should be in accordance with applicable transmission tariff provisions.

<u>IAEC</u>
The IAEC believes the 21 Critical Consumer Issues Forum principles provide a good baseline for allocation of costs. Any evaluation of this issue should take into account that there may be stranded benefits from DG customers who installed energy efficiency measures prior to investing in DG that other member-owners have funded incentives.

<u>IAMU</u>
Allocation of costs associated with distribution or transmission system upgrades is complex and will vary based on utility sector and degree of transmission ownership or

dependency. Larger DG projects may require planning studies and in some circumstances MISO planning and study requirements could apply.

MRES
Germany and Spain have recently experienced challenges with the rate structure impacts and upgrades associated with DG that Iowa should consider, learn from, and avoid. The decision of how to allocate costs should be left to the municipal utility and its customer-owners. Austin, TX and Gainesville, FL have both implemented pro-solar DG policies (value of solar in Austin; FIT in Gainesville) where citizens determined the appropriate purchase price and determined how to allocate infrastructure and power costs. The benefits to the system from the addition of DG is very local in nature and depends on load profile and customer profile, one municipal utility may benefit from peak power generation where another may end up purchasing power at times when it is not needed.

ELPC et al.
DG related distribution and transmission upgrades benefit overall savings from line losses and reduction in the need for future transmission and transmission upgrades that accrue to all customers. The benefits should be reflected in the allocation of costs related to DG transmission and distribution system upgrades. Consideration should be made so that the entire cost of an upgrade is not placed on the first developer to trigger the upgrade when other developers and rate payers will benefit from the upgrade. Iowa should look to IREC's Integrated Distribution Planning Concept paper when determining how to quantify these benefits and assign costs.[63]

ESA
The details of assigning interconnection costs are important to incentivizing increased DG, including energy storage. Cost allocations associated with distribution and transmission system upgrades should be spread among all consumers, as all will realize the benefits of these resources.

MCA
Interconnection costs for project developers and costs of review and processing by the utility need to be cost of service based to hold the ratepayer indifferent.

It is difficult to dictate an appropriate cost allocation method because each installation is unique. A DG operator should not be charged for system upgrades that the utility was previously considering or planning. Electric utilities should be required to release a list of future upgrades to the transmission and distribution systems. Properly sized and placed DG systems can help defer or avoid transmission and distribution upgrades as well as reduce peak demand to lessen transmission load, under this situation all customers will experience a degree of benefit.

[63] See generally, IREC, Integrated Distribution Planning Concept Paper: A Proactive Approach for Accommodating High Penetrations of Distributed Generation Resources (May 2013), available at www.irecusa.org/wp-content/uploads/2013/05/Integrated-Distribution- Planning-May-2013.pdf.

Sierra Club - Iowa Chapter
All customers should bear the cost of upgrades to transmission and distribution lines because all customers benefit from the upgrades. An upgrade for one DG customer may result in another DG customer not needing further upgrades.

Decorah Solar Field, Frank Belcastro Jason Hall, Jean Marie Hall, Jenn Hall, Kami Ahrens, Larry Stone, Moxie Solar, and William H. Ibanez
Distribution or transmission system upgrade cost should be borne by all utility customers because it is a necessary cost of transferring to clean energy that benefits all, through eventual price and CO_2 emission reductions. Utilities are not capable of funding those changes and will need to pass the costs to customers.

All Points Power
The answer to the question of upgrade cost allocation is dependent on the size of the DG system. Large systems may require significant upgrades where effects may be felt from great distances, so the cost should be part of the rate paid by customers. Smaller systems will have more localized effects and the expenses can be assessed as excess facilities charges by the utility.

Energy Consultants Group
Typically, DG customers consume most, if not all, of their own energy and distribution or transmission costs should not be a factor. If any energy outflows it is used locally and incrementally. Non-DG customers should pay for the fees because they are consuming the energy and create the grid demand. The benefits and savings provided to the utility by the DG customer outweigh their consumption.

Luther College
DG projects reduce line losses, produce clean or cleaner power, and also often can generate at times of peak demand.

John B. Cook
Transmission system upgrade costs should be allocated to all customers as a part of providing electricity. DG solar and other alternative energy sources are a reflection of the shifting of energy generation from coal-fired power plants and wind farms.

Industrial Energy Applications
Distribution or transmission system upgrade cost allocation depends on the cut-off definition for the DG. Benefits from a 300 MW peaking plant requiring ten miles of transmission can be felt across the utility footprint and should be treated as costs of serving all customers. Benefits of a smaller DG installation or CHP plant are confined to the DG system and upgrades are local to a customer's site and should be treated as excess facility charges.

William J. Pardee
All customers should share the cost of new transmission lines and upgrades because they will be more reliable and efficient than older lines. All society and all energy

customers benefit from DG reducing peak power purchases and reducing fossil fuel burning and extraction costs.

6. Is there adequate protection for distribution assets from improperly installed DG equipment? If not, what additional protections are needed?

IPL

For smaller inverter-based systems, IPL relies on the manufacturer's equipment following the IEEE 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems and requirements in UL 1741, the Standard for Safety for Inverters, Converters, Controllers and Interconnection System Equipment for use with Distributed Energy Resources.

On the larger DG systems a few problems may occur:

- Voltage control can be problematic when using distribution systems designed for one source of generation;

- Systems that use the full voltage range for customer support are more sensitive to voltage deviations caused by DG installations; and

- Voltage regulation on distribution systems is designed for steady state fluctuations and not the fast changes that can occur from large DG, especially during anti-islanding operations.

MidAmerican

There is adequate protection for distribution assets from improperly installed DG equipment for known DG installations that follow the current interconnection rules. If the DG installation is not maintained or is altered without notifying the utility, there is no required periodic inspection or testing that would reduce the potential for adverse effects on the distribution assets.

Consumer Advocate

The Consumer Advocate is not aware of a need for greater protection for distribution assets from properly installed DG equipment.

IAMU

There is adequate protection for distribution assets from improperly installed DG equipment as municipal utilities' local control and system planning processes enable them to respond with flexibility should significant interconnections of DG require more detailed distribution reliability analysis.

MRES

Current rules and statutes are adequate for protecting distribution assets from improperly installed DG equipment. Municipal utilities should also have the ability to adopt additional standards specific to their system, if necessary. There needs to be enforcement provisions for failure to follow interconnection procedures, safety requirements and notice mandates. The provisions should include penalties that carry significant weight such as fines or even refusal of interconnection.

ELPC et al.
ELPC et al. is not aware of any problems. Iowa's interconnection standards are based on nationwide technical standards such as IEEE 1547 and UL 1741, specifically designed to ensure the safety and reliability of distribution assets. Any problems are likely due to lack of compliance with Iowa's existing standards.

MCA
Utilities can require DG operators to install a lockable external disconnect switch and purchase liability insurance coverage which protects from improperly installed systems.

Decorah Solar Field, Frank Belcastro, Jason Hall, Jean Marie Hall, Jenn Hall, Kami Ahrens, Larry Stone, Moxie Solar, and William H. Ibanez
Systems can be designed to provide adequate protection for distribution assets to meet the evolving need of the DG systems. When the decision is made to proceed with needed growth of DG systems, utilities and developers will address installation problems.

All Points Power
Existing protection is adequate for both personnel and grid safety.

John B. Cook
To ensure adequate protection for distribution assets from improperly installed DG equipment, utilities should supervise and/or make sure installers are qualified.

Industrial Energy Applications
Existing protection is adequate for both personnel and grid safety.

7. Should the Board revise its interconnection rules in 199 IAC 45 to make them consistent with the FERC's updated interconnection rules, which were adopted on November 11, 2013, in Docket No. RM13-2-0001 (Order No. 792) and can be found at 145 FERC ¶ 61,159? In what specific ways should the Board's rules be revised?

IPL
IPL believes a pre-application report benefits all parties. The report should not be entirely duplicative of FERC rules because they are broad and not designed to address the direct impact to customers that the state's interconnection decisions have.

Under the interconnection rules, a DG system is assigned a review order giving priority to developers over customers so that characteristics of all proposed systems can be evaluated for appropriate size and impact to the overall circuit. To support development of DG for its customers, IPL encourages the Board to draw a distinction between a customer and a developer who becomes a customer only as a result of an installed DG system. IPL recommends that after an interconnection request is deemed complete, the utility assign a review order position based upon the date the interconnection request is determined to be complete, with preference given to existing customers.

MidAmerican
There are no specific items from FERC's revised rules that require immediate changes to Iowa's interconnection rules.

Consumer Advocate
It is appropriate to review whether Iowa's fees should be restructured to be consistent with FERC's new SGIP Fast Track process which was adopted due to increased penetration of small generator resources, particularly PV. The amendments are intended to remedy undue discrimination and make it more efficient and less costly for small generators (no more than 20 MW), since Iowa law also forbids undue discrimination toward renewable DG, it is appropriate to review.

IAEC
The size of generation interconnected under FERC rules most likely will not take place on the DG system the Board has defined for purposes of this docket.

IAMU
Municipal utilities are not subject to Board interconnection rules.

MRES
The Board should consider adoption of FERC rules as well as IEEE or any other best practices policies. Municipal utilities are not subject to Board interconnection rules.

ELPC et al.
The Board should initiate a rulemaking docket to revise Iowa's interconnection standards to incorporate best practices from the FERC SGIP.

ESA
FERC amended the SGIP with Order 792 to include energy storage as small generating facilities with access to Fast Track interconnection processes. ESA recommends that Iowa adopt Order 792 rules as they are deemed applicable to energy storage projects in the state.

Additionally, a recent decision from the California Public Utilities Commission allows additions or enhancements to net metering-eligible systems to be exempt from certain fees. Where energy storage is considered an enhancement to a renewable energy generation facility and directly connected behind the same billing meter, certain upgrade charges are not applied to the energy storage facility.

MCA
The following points within 145 FERC ¶ 61,159 should be addressed and covered within Iowa's interconnection regulations:

- Allow interconnection customers to obtain a pre-application report on system conditions at possible interconnection points;
- Raise the threshold for the Fast Track application process to 5 MW;
- Revise the procedures governing customer meetings and supplemental review under the Fast Track process; and
- Allow interconnection customers to provide written comments on upgrades deemed necessary for interconnection.

According to FERC these revisions will reduce the time and cost to process small generator interconnection requests while maintaining reliability, increasing energy supply, and removing costly barriers to clean DG. The MCA agrees with this position and believes these points should be incorporated into Iowa's interconnection procedures.

Sierra Club - Iowa Chapter
The Board could revise the Iowa rules in line with what Ohio did in response to Order No. 792:

- Increase the capacity threshold for simplified Level 1 interconnection review from 10 kW to 25 kW for inverter- based systems and reduce the initial review time from 1 month to 15 business days;

- Adopt flexible size eligibility requirements for Level 2 Fast Track interconnection review that expands beyond the current 2 MW limit, depending on proximity of a generator to a substation and line voltage levels;
- Implement a uniform, well-defined supplemental review process for applications that may fail one or more initial review Fast Track screens;

- Adopt the emerging best practice of using 100 percent of minimum load as a penetration screen in the supplemental review process; and

- Require utilities to provide interested customers with a pre-application report, for a $300 flat fee, to help identify areas on the grid that will accommodate DG.

Winneshiek Energy District
Current interconnection rules should be revised to be consistent with FERC Order 792, including new Fast Track interconnection criteria for small generators, and energy storage projects. There have been numerous complaints in recent years from Winneshiek County residents who are frustrated by administrative timelines and delays for PV projects. Customers on this circuit have had difficulty obtaining interconnection, including what they understood initially to be verbal denial of access, based apparently

upon the outdated 15 percent screen used prior to Order 792. Adoption of FERC's Order 792 will clarify and streamline this process for utilities and customers alike.

<u>All Points Power and Industrial Energy Applications</u>
FERC's jurisdiction is transmission voltages and Order 792 applies to interconnections with the transmission system. For the most part, DG projects are going to be interconnected at the distribution level, where Order 792 would not apply. Rule 199 IAC chapter 45 governs the electric interconnection of DG facilities and is based heavily on IEEE 1547. It has been in place for over ten years and is quite adequate to govern the installation of DG systems for the foreseeable future. To attempt to meld together two sets of rules, where each have divergent uses, would be counterproductive.

<u>Jason Hall, Jean Marie Hall, Jenn Hall, Kami Ahrens, Larry Stone, Moxie Solar, and William H. Ibanez</u>
The Board should not revert to a lesser program overseen by FERC. The Board should step up involvement of REC and municipal utility oversight and implement net metering requirements to all utility companies operating in Iowa, these initiatives are backed by multi-lateral government support and overwhelming public support of renewables and DG in Iowa.

8. Should the Board require any customer installing DG with a view toward selling excess generation to the utility to commit to remaining interconnected for a specific period of time, to maintain the DG system in good working order for that entire time period, and to either obtain a similar commitment from any subsequent purchaser of the property or to remain responsible for the commitment for that entire period of time. If so, why? If not, why not?

<u>IPL</u>
Such requirements would be ideal for utilities by promoting long-term interconnection safety and certainty. IPL understands the difficulty this could place on property sales for the seller and buyer. IPL is open to discussing this issue further.

<u>MidAmerican</u>
The DG owner is obligated in the interconnection agreement to operate and maintain interconnection facilities in good working condition in order to protect the reliability of the electric system. Additional commitments regarding excess generation would place a considerable effort on the state or interconnected utility to inspect and enforce such requirements. Additionally, what criteria would be used to determine if a DG facility is properly maintained? If the DG facility is not properly maintained, what would be the remedy? How would disagreements with the DG owner be resolved? The requirements could also cause interference with a property owner wanting to sell property.

Consumer Advocate
DG represents a sizeable investment for most customers and it is likely the customer will be motivated to maintain the DG system in good working order and remain interconnected. The utility is only responsible for paying the DG for actual generation. More specific commitments should not be required of a small DG. The shifting of production risk to small DGs through contractual commitments may result in inappropriate and unnecessary barriers. For larger DG installations, such commitments may be more reasonable and acceptable.

IAEC
The type of commitments suggested in this question are appropriate for negotiation between the utility and the DG customer as the commitment to remain connected and provide output for a specified time period may impact price. PURPA provides that a qualifying facility has the ability to decide if it wishes to make energy available to the utility and the time period. The Board should not establish mandates that remove the parties' ability to negotiate or the DG owner's ability to make choices about what to do with its generation output.

IAMU
If a municipal utility allows DG intended to produce significant energy/capacity to sell to the utility it needs to be committed for a time period commensurate with the terms of purchase so the utility can plan for resources. Municipal utilities should be able to negotiate PPAs that reflect the resource value and the relationship between the utility and the supplier. Depending on the size and capability of the DG installation, it may need to meet additional MISO performance obligations that could be included in the PPA.

MRES
DG customers seeking to sell power should follow the municipal utility's electric policy like any merchant plant selling power. There should be a contract with the municipal utility setting the purchase price, term of the contract and equipment maintenance, safety, and insurance specifications. It may be appropriate for the state to set minimal requirements (maintaining insurance, maintaining outside disconnect equipment, providing notice of planned disconnection/non-generation), however the municipal utility is in the best position to negotiate its own interconnection agreement with the DG facility. On the sale of the property it should be left to the city and the owner to negotiate transfer of property issues in the original interconnection agreement.

ELPC et al.
Federal law does not require a commitment to remain interconnected for a specific period of time. Interconnection and net metering billing arrangements are not entered with the intent to sell excess generation. Systems are designed to offset the customer's on-site load or average annual consumption. These systems typically do not have a major adverse impact on the electricity grid.

Currently MidAmerican and IPL do not include DG or energy efficient resources in their integrated resource plan, but instead reflect these in their load forecast. Rather than require a commitment to remain interconnected, the Board should require electric service providers to account for the long-term performance of DG and evaluate them as a separate resource option.

MCA

From a resource planning perspective it is understandable that utilities would want to know the duration DG customers plan to remain interconnected especially if the customer exports electricity. Regulations for these commitments could prove onerous and prohibitive for potential clean CHP systems. A PPA or a FIT will better ensure interconnection for a set time frame. This incentivizes a CHP operator with a revenue stream while at the same time contractually ensuring the utility that the CHP operator will remain connected to the grid.

Commitments to good working order are met with the current disconnect switch option, liability insurance requirement, and stand by rates that motive DG customers to maintain equipment in proper working order.

Winneshiek Energy District

It is doubtful that a long-term grid connectivity contract requirement as a simple pre-requisite to grid access would hold up in court. A simple time commitment from the DG owner is undesirable. Positive economic and administrative arrangements for customer-owned DG can serve the societal good of promoting long-term grid connectivity. True FITs generally incorporate long-term contracts, without linking production to consumption.

Decorah Solar Field, Frank Belcastro, Jason Hall, Jean Marie Hall, Jenn Hall, Kami Ahrens, Larry Stone, Moxie Solar, and William H. Ibanez

The Board should require any customer installing DG with a view toward selling excess generation to the utility to commit to remaining interconnected for a specific period of time, to maintain the DG system in good working order for that entire time period, and to either obtain a similar commitment from any subsequent purchaser of the property or to remain responsible for the commitment for that entire period of time. This is necessary to maintain a dependable distribution system.

All Points Power and Industrial Energy Applications

In order for a DG owner to receive financing approvals or make investing decisions there needs to be economic assurances. A PPA or a FIT is a more effective way of obtaining mutual commitments between the DG owner and the utility. In order to promote DG in Iowa, a solid economic and financing basis needs to be promoted, not the proposed long-term commitments from only the DG owner.

Energy Consultants Group
An argument can be made to promote DG customer commitments under a FIT. The utility company does not own the equipment and should not be dictating what happens behind the meter.

Luther College
If the Board decides to implement FITs, or some form of value of renewable pricing that involve long-term, multi-year power purchase contracts, it may make sense to require owners of such DG systems to commit to remaining interconnected for a specific period of time and to maintain their system in good working order. Such requirements are routine in PPAs. It is not clear that this is necessary today for systems that fall under the current 500 kW net metering limit.

John B. Cook
If the DG installation is subsidized by the utility, time and system maintenance commitments should be permitted. Most DG owners will have their own incentives to keep and maintain the system, but there are unavoidable circumstances that may alter that ability. Requiring an unreasonable commitment would discourage DG.

9. For customers that have installed DG, what have been the positive and negative experiences when interconnecting with the utility and what specific changes would you suggest? (Identify whether the DG facility was renewable or nonrenewable and which utility you interconnected with.)

a. Does the interconnection process timeline take longer than necessary? If so, what are the problems and how can they be solved?

b. Has any DG owner-commenter experienced difficulty interconnecting a DG project with the system of any non-rate-regulated utility or utilities? If so, please describe the difficulty experienced and whether/how the difficulty was resolved.

Craig Mosher
There is too much paper and fees associated with set-up and approval of the interconnection agreement. The process needs to be streamlined and made more cost effective to encourage more DG.

Decorah Solar Field and Frank Belcastro
As customers that have installed DG several times, the installation process should be simpler as the demand for DG increases and utilities encourage the development of DG. Currently the process is not well understood by customers and discouraged by utilities. The interconnection process timeline takes too long to implement and there is not an understandable explanation for the delay.

<u>All Points Power</u>
For larger facilities, the process is too long. In one case, a customer waited over 12 months and they were denied an interconnection agreement because there was not technical savvy and resources within the utility to support the equipment the customer had spent tens of thousands of dollars on. Hiring and retaining technical resources will allow for timely processing. There also needs to be a grievance process for customers to utilize to resolve disputes.

<u>Farm Energy, LLC</u>
Experience is generally positive. The net metering system seems unfair and would likely be better off it was replaced with a FIT under a long-term contract or a net metering that doesn't cash-out at year end when generation is lower in January.
Yes, the interconnection process takes longer than necessary, extending standardized interconnection to non-rate-regulated utilities and adopting all sections of IEEE 1547 are suggested.

Farm Energy LLC is developing a 2 MW wind project that has experienced difficulties with interconnection. The project was detailed in a previous Board DG interconnection docket and has yet to finalize a PPA. This project would likely be operational today if Iowa had a properly designed FIT and standardized interconnection that adopted all sections of IEEE 1547.

<u>EPo Energy</u>
Installer Experiences:

- Tim Graber: The majority of the process was timely. The process to change out the meter and receive the permission to operate was the longest, taking about 30 days.

- Paul Reed: IPL did well on our first system but the last process was significantly longer.

- Porter Farms: Our Access Energy locations were very efficient. The IPL process is cumbersome and ever increasing in complexity. Waiting on the letter grating permission to operate also slows things down.

- Todd Lorack: The process went quickly with very little issues.

- Darrell Egli: I have done two interconnections with IPL and the second one took a lot longer.

- JG4 Hog LLC: The process went well. IPL's process is more tedious and time consuming in 2014 than 2013. There needs to be more clarity on what the inspectors are requiring for interconnection.

- Porter Farms: Access has been great to work with on interconnection and their process is easier and more streamlined than the IPL process.

Energy Consultants Group

Overall the process is not bad, but IPL’s administrative process is brutal, inefficient, and flawed taking months to complete anything. A unified structure with required response times provided and overseen by the Board is needed. IPL’s interconnection process timelines are inconsistent. This topic is complicated and needs streamlined among the utilities.

Energy Consultants Group has received and experienced many complaints with interconnecting a DG project. One customer submitted a Level 2 interconnection agreement and provided all the documents required but did not place a period after Inc in the business name. The application was rejected for this reason and took over three weeks to get it back in the mail. When it was resubmitted it took another month to get processed. How hard would it been to call the customer and verify the name and place a dot on the application and move on?

Jason Hall, Jean Marie Hall, Jenn Hall, Kami Ahrens, Larry Stone, William H. Ibanez, and Moxie Solar

As customers who have installed DG several times, the process could be simplified as it is currently unclear to customers and discouraged by utilities. Interconnection process timeline takes too long to implement and applications are not prioritized by utility companies. There has been difficulty with interconnections related to an agreement being denied due to overproduction in a region, which is confusing since the DG systems are constructed to offset onsite electricity demands. There needs to be a publication of where/how/why these issues may occur so that DG operators are not wasting money on a system that will be denied.

Luther College

The Luther College wind project was one of the first projects to be reviewed by IPL under the new interconnection process approved by the Board several years ago. The process worked well, though it did seem to take every day allotted for each stage of review. Luther College had a similar experience with the 280 kW solar project that is currently leased.

Industrial Energy Applications

Interconnection process timelines are understandably different based on the scale of the project and whether the agreement involves negotiations. There is one situation where a customer spent tens of thousands of dollars on a full paralleling switch gear, but had to ultimately accept a closed transition operation because the utility did not have appropriate technical resources to specify what was needed in terms of relay settings. The process took over a year and there was no appeal option for the customer. Utilities need more knowledgeable, trained technical resources supporting the interconnection process.

Robert Fischer
Since constructing a new home and interconnecting to IPL in November 2010, the system has supplied 100 percent of the home's power requirements. The interconnection process was positive, with only a slight delay between the installation date and interconnection.

10. Comment on whether you believe the Board has jurisdiction to extend its interconnection rules to coops and municipal utilities and if so, whether it should exercise such jurisdiction.

Consumer Advocate
The Consumer Advocate believes the Board has jurisdiction to extend its interconnection rules to non-rate-regulated utilities. In doing so, the Board will help ensure common interconnection standards and provisions to maintain necessary safety standards while eliminating unnecessary obstacles and preventing barriers.

While the Board did not make non-rate-regulated utilities subject to its interconnection rules, the Board expressed its intent to monitor interconnection issues and consider steps to modify or extend the application of its rules to non-rate-regulated utilities as necessary. This inquiry proceeding presents an appropriate opportunity to make these considerations.

IAEC
The Board has already extended the interconnection rules to the RECs. See 199 IAC 15.10. The Board adopted a new chapter of rules (i.e.199 IAC 45) as a result of a rate making standard added at the federal level. The Board chose to apply chapter 45 to those electric utilities that are rate-regulated by the Board. Many of the RECs have modified their tariffs to be consistent with the 199 IAC chapter 45 rules; however, the IAEC does not believe the Board should mandate compliance. Some provisions in chapter 45 could be viewed as interfering with the non-rate-regulated utilities' ability to establish their own PURPA implementation plan. The same jurisdictional issue that precludes the Board's imposition of the net metering mandate on the RECs and municipal utilities would be implicated if the Board attempted to make all of chapter 45 applicable to said utilities.

IAMU
The IAMU does not believe that the Board has jurisdiction to extend interconnection rules to municipal utilities. Municipal utilities are governed by a City Council or Board of Trustees charged with making decisions regarding the utility. Iowa Code section 384.84, subsection 1 states that "[t]he governing body of a city utility … may establish, impose, adjust and provide for the collection of rate and charges to produce gross revenues at least sufficient to pay the expenses of operation and maintenance of the city utility…"

The Board only has jurisdiction over municipal utilities that are listed in section 476.1B or otherwise provided by statute. It is the IAMU's contention that if the Board wants to require municipal utilities to adopt particular interconnections procedures and standards, it would have to be accomplished through state legislation.

MRES

It may be appropriate that the state set some minimal requirements (e.g. maintaining insurance, maintaining outside disconnect equipment, or providing notice of planned disconnection/non-generation). The municipal utility is in the best position to negotiate its own interconnection agreement with the DG facility. MRES and its members have developed an interconnection policy and manual.

Deference should be given to the municipal utilities to establish interconnection policies that are unique to their own system and safety needs. There is no reason or need for the Board to extend its interconnection rules to include municipal utilities.

ELPC et al.

Net metering and interconnection standards are within the jurisdiction the Board has over RECs and municipal utilities. RECs are subject to "all other regulation and enforcement activities of the Board"[64] and municipal utilities are subject to Board regulation related to statutorily specified areas. The Board has explained that this authority "extends to, among other things, safety standards, assigned areas of service, and prohibition from discrimination against users of renewable energy."[65]

Iowa has adopted interconnection standards[66] which address safety and fair treatment of all utility customers – areas that the Board has explicit authority to regulate.[67] Differences and discontinuities between utility interconnection procedures create inefficiencies and market confusion that can raise costs for DG project development. Customers should not be deprived of the opportunity to interconnect and self-generate under standard procedures solely because they are served by an REC or municipal utility. When the Board updates the interconnection rules, it should extend the applicability of those rules to RECs and municipal utilities.

Sierra Club - Iowa Chapter

The Sierra Club - Iowa Chapter believes the Board has jurisdiction and should exercise that jurisdiction to extend interconnection rules to RECs and municipal utilities. PURPA would not preempt state regulation of interconnection standards as the Board would not be regulating rates. The Board has the authority to prohibit discrimination of the standards offered to customers of rate-regulated utilities and not to customers of RECs and municipal utilities. Iowa Code § 476.21.

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[64] Iowa Code § 476.1A.

[65] IUB Docket No. NOI-06-4, Order Adopting Preliminary Model Interconnection Procedures, p. 6 (April 25, 2007).

[66] See 199 IAC 45.

[67] See, e.g., In re. Iowa Lakes Electric Cooperative, IUB Docket No. WRU-06-19-978, Order Denying Waiver Request (Sept. 5, 2006) (holding that RECs are subject to the Board's rules limiting charges for meter testing, even though the RECs are not rate- regulated utilities).

Energy Consultants Group
The Board has and should exercise jurisdiction to extend interconnection rules to RECs and municipal utilities.

Jason Hall, Jean Marie Hall, Jenn Hall, Kami Ahrens, Larry Stone, William H. Ibanez, and Moxie Solar
The Board has jurisdiction over RECs and municipal utilities and should extend the terms and requirements to these entities. Many of these utilities do not allow DG on their systems (FERC already requires them by law to allow interconnection) and get away with it because the customer doesn't know any better, or doesn't want the fight. Accountability would improve if there were one governing law and body in Iowa.

John B. Cook
The Board has jurisdiction to extend its interconnection rules to RECs and should require that they follow the same rules as other utilities.

General Interconnection Comments

ESA
ESA believes that energy storage should be an integral part of an Iowa DG plan. Energy storage is a tool that can enable expanded renewable integration, provide consistent output, coordinate supply to load in real time, and mitigate challenges from increased dynamic resources.

Winneshiek Energy District
The more onerous and costly the interconnection process is perceived to be, the more attractive DG plus storage and grid defection become. Large-scale defection is not likely in the very near future but current actions by regulators and utilities create the foundation for future plans and relationships. Community (or Shared) renewables, also by definition, maintain grid connectivity among all participants.

Community renewable energy options encompass both the net metering and interconnection aspects of the current comment request. They solve many challenges being addressed. Winneshiek Energy District strongly recommends Iowa move forward with enabling policy on community or shared renewable energy options.

The "Utility Community Solar Handbook" included in the current Board order focused on just utility-owned community renewable energy projects. Page five states "this handbook provides the utility's perspective on utility managed community solar program development … It is important to understand the utility's motivation for considering a community solar program."

In the context of this docket, understanding the customer and community's motivation for desiring a community solar program is important. DG is fast becoming economically viable for a wide array of customers. The economic viability of DG plus storage is on the horizon. Climate responsibility and localism are equal if not greater drivers of DG, and will continue to be into the future. The electric utility industry as a whole has been strongly anti-DG and resistant to climate action throughout Iowa and the country. The extensive benefits of community renewable energy projects are unlikely to be realized by utility-owned community solar projects, any more than their green power options were bought by customers. For these benefits to be realized, community renewable programs should follow key guiding principles, as described in the IREC's "Model Rules for Shared Renewable Energy Programs":[68]

- Shared renewable energy programs should expand renewable energy access to a broader group of energy consumers, including those who cannot install renewable energy on their own properties.

- Participants in a shared renewable energy program should receive tangible economic benefits on their utility bills.

- Shared renewable energy programs should be flexible enough to account for energy consumers' preferences (including business and ownership models).

- Shared renewable energy programs should be additive to and supportive of existing renewable energy programs, and not undermine them.

Community renewables are an opportunity to meet many of the needs and motivations of customers within the context of grid integrity.

<u>Chris Hoffman of Moxie Solar</u>
Safety benefits of renewable energy saving in health care and weather related emergency service costs have been identified by the Obama Administration. DG installation reliability is improving daily.

<u>Wendy VanDeWalle</u>
The time table to turn on my solar array with IPL took a week but I have heard that it has taken longer with other customers. There is a need for public to be more informed about the interconnection process. A recent story in the news about a person forced to take down self-installed DG or have electricity turned off sends a message that DG is frowned on by utilities.

[68] Available at http://www.irecusa.org/publications/ under the "regulatory" heading.

Summary of Responses to Customer Awareness/Protection Questions

1. Is there a need to educate customers about DG issues such as economics, tax incentives, utility requirements, reputable installers, and similar considerations? If so, whose role is it and what type of education should be provided?

IPL

IPL recognizes the importance of reliable information and guidance for educating customers about DG issues but feels IPL's role is limited to providing the utility requirements and resources for other related issues. IPL currently provides the following DG information:

- alliantenergy.com/sellmypower – provides utility requirements, including a high-level overview of the process steps, standard DG documents, applicable rules, IPL's *Technical Guidelines and Requirements for The Interconnection of Parallel Operated Generation*, tariff and power purchase information, plus links to pertinent resources.
- Distributed Resources and Renewable Energy Hotline dedicated team.

The Iowa Energy Center also provides DG educational information for customers.

MidAmerican

Due to the tremendous amount of information available, there is a need to educate customers about DG issues. Iowans need to have objective, factual information available to make DG decisions. MidAmerican has DG information on its web site covering; installation basics, safety, reliability, rate structure and frequently asked questions. Tax incentives and reputable installers are outside of the utility's scope. It would be appropriate for the Board or another state agency to be known as a reliable source leading Iowa consumers to factual information on all aspects of DG.

Consumer Advocate

Customer education is contemplated within the renewable energy programs authorized as part of reasonable and adequate electric utility service in Iowa Code § 476.8.

IAEC

RECs have a key role in educating its member-owners about issues associated with DG. The Iowa Energy Center is also a good resource currently available to customers. The Board and other state agencies should also participate in education by offering individual meetings, webinars, workshops, web sites, newsletters, magazines, and pamphlets.

IAMU
Municipal utilities should be responsible for educating their customers about DG, especially on utility-specific questions. Customers should have easy access to independent and unbiased DG resources. The Iowa Energy Center and the Department of Energy's Office of Energy Efficiency and Renewable Energy are good resources for information.

MRES
Customers should be educated about DG issues in Iowa. The Iowa Energy Center and the National Renewable Energy Laboratory (NREL) are good resources for information. The Board should set up a web site containing tax incentive information, basic interconnection requirements, notices regarding disreputable installers and scams that municipal utilities can direct customers. The site should also give information to customers on how to report a scam and how to seek retribution and damages if they have been subject to a scam.

ELPC et al.
With emerging markets and technologies, customer education is needed and should come from utilities, commissions, operators, and any other involved party. The Board should ensure that education is transparent with respect to the benefits and costs of DG. DG customers need to have access to information on reputable dealers, utility requirements, and other considerations. As DG usage increases the Board can incentivize larger investments in grid infrastructure modernization, better emergency management, and advanced metering technology.

Examples of state outreach:

- California has an entire governmental outreach web site as a resource to customers interested in implementing rooftop PV that includes savings calculators, an event calendar, contact listings, and incentive programs.

- In Arizona, the Arizona Corporation Commission has led an effort for the utilities to explain renewable energy standards, provide solar maps, mention state and federal incentives, and list residential program details for each utility in the state.

- In New Jersey, representatives from government, industry, energy experts, public interest groups, and academics helped establish committees to engage stakeholders in New Jersey's Clean Energy Program development and provide input to the Board of Public Utilities regarding the design, budgets, objectives, goals, administration, and evaluation of New Jersey's Clean Energy Program.

- The Massachusetts Clean Energy Center provides online information for customers and provides additional information related to clean energy development in the state, including informational resources, solar and wind programs, and recent developments.

<u>ISETA</u>
ISETA supports increasing awareness and educational activities.

<u>Sierra Club - Iowa Chapter</u>
The Board is in the best position to provide objective educational DG information to customers. The utilities would be placed in a position to advocate against their own interests and should not be providing customer education. The information provided should include; nature of available DG technologies, benefits and challenges of installation, certified installer list, interconnection standards, terms and definitions, utility requirements and available tax credits.

<u>Decorah Solar Field and Frank Belcastro</u>
There is a need to educate customers about DG issues such as economics, tax incentives, utility requirements, reputable installers, and similar considerations. Utilities and installers should provide the necessary information.

<u>All Points Power and Industrial Energy Applications</u>
Consumer education is critical to long-term DG adoption and should be left to market participants. The Board's role should be to enable DG.

<u>Energy Consultants Group</u>
Utilities should be responsible for educating customers. They should be required to provide education seminars and place reference information on customer bills. Educational information should also be easily accessed and available on their web sites.

<u>Jason Hall, Jean Marie Hall, Jenn Hall, Kami Ahrens, Larry A. Stone, and Moxie Solar</u>
Utilities and installers should cooperate to provide customers educational information on DG issues such as economics, tax incentives, utility requirements, reputable installers, and similar considerations.

<u>Luther College</u>
There is a need to educate Iowans about the economics, regulations, and practical aspects of DG projects. The Board may want to develop a comprehensive list of resources to direct interested parties to such as the Iowa Energy Center. Luther College's Center for Sustainable Communities offers workshops and the Winneshiek Energy District also provides online resources.

<u>John B. Cook</u>
Utilities should be responsible for educating customers about DG issues such as economics, tax incentives, utility requirements, reputable installers, and similar considerations in an easy to find format. Currently, this information is not easily available from the utilities.

John E. Carpenter
There is a need to educate and demystify renewable energy to all utility customers. If the utility believes in DG it is the role of the utility to educate.

Wendy VanDeWaller
The public needs to be more informed about DG so that they feel enabled to use appropriate installation resources.

2. Should the Board develop a checklist to assist customers in understanding the process and responsibilities associated with installing DG or does one already exist? What issues should consumers consider when installing DG (both renewable and nonrenewable)?

IPL
A DG checklist should be developed and widely available via the electric utility, Iowa Energy Center, the Board, and the Consumer Advocate web sites. IPL included a customer checklist for rooftop solar[69] authored by Edison Electric Institute and suggested it could be used as a starting document to develop a similar checklist for Iowa.

MidAmerican
The Board should take reasonable steps to ensure that DG participating customers have access to a variety of reliable sources and are making informed choices. The Iowa Energy center is a source of information. The Board should provide links to information on its web site. MidAmerican's web site includes a DG decision-making checklist for rooftop solar and has recently added the following information to aid customers.[70]

- A description of DG;
- Material on how energy is delivered to a traditional customer and a DG customer;
- Responsibilities of a DG customer;
- Description of the interconnection process;
- Discussion of safety and reliability aspects; and
- DG rate structure options.

Consumer Advocate
In the recent energy efficiency dockets, MidAmerican and IPL were directed to offer information to help guide customers in assessing the feasibility of DG.[71] This could

[69] See Attachment A of IPL's comments filed June 24, 2014.
[70] http://www.midamericanenergy.com/environment7.aspx.
[71] Interstate Power and Light Co., Docket No. EEP-2012-0001, "Final Order," p. 35 (the Board suspended the part of the renewable energy program that pays incentives to customers for renewable installations, but directed IPL "to continue offering the information and technical assistance for renewable projects that it currently offers by providing this as part of its outreach, education, and training program.") (IUB, Dec. 2,

include such a checklist. The availability of information should be sufficient with respect to MidAmerican and IPL customers, the Board may want to reference a checklist to help guide interested customers toward the extensive information available through the IOU's education, outreach and training efforts.

IAEC

A checklist can be a valuable tool for interested DG customers. The IAEC provided a copy a DG checklist[72] its membership uses.

IAMU

Development of a checklist is in line with customer education. The Iowa Energy Center should develop a checklist with referral to the local utility.

MRES

It is advisable that the Board, the Consumer Advocate, or Iowa Energy Center establish a DG Installation 101 Education Checklist that can be distributed or accessed on the Web. Customers should also be directed to meet with their local municipal utility to discuss potential issues unique to the municipal utility. Communication of compliance with laws, safety standards and operational mandates are important subjects to be considered on the checklist.

ELPC et al.

An objective simple checklist available as a quick reference to those interested in DG is always helpful. Customers should consider:

- Retail rates offered by utilities. Confirmation that there is no charge for onsite generation;
- Rooftop vs community solar projects and their comparative benefits;
- Home rooftop solar financing resources and considerations; and
- Receiving bids from a variety of providers.

The Board should be mindful and wary of community rules or civic ordinances restricting the development of solar in Iowa. Iowa Code currently enables city officials to prohibit deeds for property located in new subdivisions from containing restrictive covenants such as unreasonable restrictions on solar. See Iowa Code § 564A.8. The Iowa Code should be extended to all neighborhoods and broader provisions in place to prevent covenants prohibiting solar implementation.

2013); and MidAmerican Energy Co., Docket No. EEP-2012-0002, "Final Order," p. 39 (the Board did not require MidAmerican to offer a renewable program that pays incentives to customers for renewable installations, but directed MidAmerican "to offer information and technical assistance for renewable projects by providing this as part of its outreach, education, and training program.") (IUB, Dec. 2, 2013).

[72] IAEC comments filed June 24, 2014, page 19.

Sierra Club - Iowa Chapter
The Sierra Club - Iowa Chapter has produced a fact sheet[73] on this issue that includes many items for consumers to consider prior to purchasing solar panels or a wind turbine.

Decorah Solar Field, Frank Belcastro, Jason Hall, Jean Marie Hall, Jenn Hall, Kami Ahrens, Larry A. Stone, and Moxie Solar
The Board should develop a checklist to assist customers in understanding the process. Considerations for the checklist should include:

- Amount of energy used and rate paid during the last 12 months;
- Recommended number of panels and panel layout;
- Site preparation and condition of the roof if a roof mount;
- Estimated cost of the system and cost per watt of recommended capacity;
- Equipment manufacturer and warranty;
- Comparison of inverter systems;
- Estimated interconnect cost, annual insurance, taxes and upkeep cost; and
- Estimated rebate and tax credits and estimated payback period.

All Points Power and Industrial Energy Applications
Developing a checklist would be better served by market participants with the Board limiting its role to that of an enabler.

Energy Consultants Group
The Board should develop a simple checklist but it will only be effective if a standard system is adopted. A checklist already exists please refer to the North American Board of Certified Energy Practitioners (NABCEP).

Luther College
It would be helpful for the Board to develop a checklist for customers as they explore potential investments in DG.

John B. Cook
The Board should develop a checklist of consumer information that utilities are required to give customers.

John E. Carpenter
The Board should develop a clear statement about what DG is and its future in Iowa's energy landscape. The utilities should develop practical checklists.

Steve Demuth
The Board should have a long-term strategic plan to encourage DG which should include documentation of the responsibilities of DG customers such as a checklist.

[73] See attachment to the Sierra Club – Iowa Chapter comments filed June 24, 2014.

William J. Pardee
Hawkeye REC is doing a decent job of educating its customers on solar installation issues.

3. With respect to public safety, who is primarily responsible for the issue of firefighter safety and fire suppression activities, the customer or the local fire officials?

   a. Should customers be required to provide local fire officials information regarding their solar installations?
   b. Should fire officials be required or encouraged to maintain detailed logs regarding solar installations in their community or fire district?

IPL
IPL finds the "Fire Fighter Safety and Emergency Response for Solar Power Systems" report provides best practice guidance for emergency response. IPL recommends the Board contact Barbara Mentzer to gain her expertise and guidance on this subject.

MidAmerican
Two primary concerns with solar DG in firefighting activities are ability to disconnect power sources and access to rooftops. Both issues are addressed in the 2012 International Fire Code at section 605.11 which also includes requirements for marking electrical equipment and locations. The code also contains requirements for access, pathways, and smoke ventilation for rooftop solar collectors. The Iowa Fire Marshal and most Iowa cities have adopted the 2009 International Fire Code, not the 2012 version. A 2015 version under development is expected to include the 2012 requirements and more.

Customers should be required to provide local fire officials details on all DG installations. Fire departments typically maintain detailed records by address on facilities such as fuel storage tanks registered with the fire department. Solar installations could be flagged in a similar manner as an additional cross-check in the event that the facility is not compliant with code.

Consumer Advocate
Firefighter safety and fire suppression activities are likely overseen by the State Fire Marshal Division of the Iowa Department of Public Safety. State law dictates the conditions in which a citizen is responsible for firefighter safety and fire suppression activities on their property.

IAEC
The State Fire Marshal is responsible to promote fire safety and promulgate fire safety rules. Customers who elect DG should be responsible for following safe and proper installation procedures in a manner that does not create a fire hazard or increase firefighter danger. Requiring customers to provide information regarding solar installations to local fire officials lies within the Board to coordinate with the Iowa

Department of Public Safety, the State Fire Marshal and any other interested parties. A legislative change may be needed in requiring fire officials to maintain detailed logs regarding solar installations in their community or fire district.

<u>IAMU</u>
The Board should engage local fire officials and the State Fire Marshal's office to discuss these questions.

<u>MRES</u>
MRES supports adopting the National Electric Code that was updated in 2012 to include fire safety requirements for solar installations. Each municipal utility should work with their local rescue units to determine unique safety issues to be addressed through ordinance or the interconnection agreement. Local rescue units should be encouraged to keep up to date records and seek out continuing education and fire safety protocols.

<u>ELPC et al.</u>
Issues related to fire safety and solar PV are being evaluated, studied, and addressed with a combination of improved and revised building and fire codes, including the 2012 International Fire Code, and firefighter training and education. Nationally available resources and best practices on these topics are available to guide next steps in Iowa, including specific fire safety information and resources available from the Solar Energy Industries Association[74] and the Solar ABCs.[75]

<u>ESA</u>
Fire departments need to understand the chemistry and proper handling of various energy storage technologies in case an emergency situation occurs. ESA recommends developers have a clear reporting mechanism for installations and thorough understanding of fire safety requirements.

<u>All Points Power</u>
Firefighter safety is ultimately the responsibility of the individual firefighters. Fire departments have programs to provide detailed information regarding specific hazards at given locations. Larger facilities have detailed response plans. Fire officials should maintain records for all locations that would involve significant and/or unusual risk. DG owners are responsible for providing proper notification and diligently reporting changes so that first responders are aware of hazards they may face.

As with Occupational Safety and Health Administration (OSHA) requirements for hazardous material postings, DG owners should be required to provide warning placards regarding specific hazards that first responders may face including; battery systems, PV equipment, high pressure steam or gas, etc. Fire officials should be

[74] SEIA, Issues & Policies, Fire Safety & Solar available at: http://www.seia.org/policy/healthsafety/fire-safety-solar (last visited June 24, 2014).
[75] Solar America Board for Codes and Standards, Fire Fighter Safety in Buildings with PV Modules available at: http://www.solarabcs.org/current-issues/fire_safety.html (last visited June 24, 2014).

encouraged to maintain records regarding solar installations in their community or fire district.

Energy Consultants Group
Fire officials are responsible for safety in regards to emergency response and there is training available to deal with a DG facilities in such emergencies.

Energy Consultants Group is working on a system for DG customers to provide solar installation details to fire officials as well as a system for maintaining those details by the fire officials.

Jason Hall, Jean Marie Hall, Jenn Hall, Kami Ahrens, and Tim Brodersen of Moxie Solar
DG owners should be responsible for providing local fire officials information regarding their solar installations.

Luther College
Accident response planning is necessary for all DG projects. Utilities should forward all DG interconnection agreements to local fire and rescue officials to keep on file.

John E. Carpenter
Properly installed solar installations are not fire risks.

Chris Hoffman of Moxie Solar
DG owners should provide fire officials with information regarding their solar installations and fire officials should be encouraged to maintain logs regarding solar installations within their fire district.

Industrial Energy Applications
Safety starts with firefighters and first responders. Customers need to provide information in a timely manner so that fire departments can maintain a record system of potential hazards.

Customers are responsible for providing solar installation details to local fire officials just as they would be for any other hazardous material. In addition, customers need to appropriately placard and post information for the installations. Fire officials should maintain detailed logs regarding solar installations, similar to that used for hazardous materials.

William J. Pardee
There are not any special fire risks associated with his stand-alone PV system. Customers should not be required to provide local fire officials information regarding solar installations as it would be a nuisance to both parties. Fire officials do not need to keep detailed logs of solar installations in their community because solar installations create less risk than LP gas furnaces, water heaters, or many other common household risks.

4. Do current Iowa consumer protection laws adequately address the responsibilities of the DG suppliers/distributors? Who should be responsible for resolving consumer complaints regarding DG suppliers/distributors (Iowa Utilities Board, the Attorney General's office, or some other agency)?

IPL
The Attorney General's (AG's) office should be responsible for resolving consumer complaints regarding DG suppliers or distributers. The AG's office is responsible for determining the adequacy of current Iowa consumer protection laws. IPL will work with the AG's office as necessary to ensure laws are appropriately addressing the responsibilities of the DG suppliers and distributers and will provide customers with current fraud protection information.

MidAmerican
The level of regulation appropriate for DG in all respects depends on the role DG is intended to serve as an energy resource. When DG is compensated as any other power source used by utility customers, DG should be regulated by the Board as any other utility supply resource to ensure it is readily available to customers.

Beyond the interconnection process, there is limited regulation of DG suppliers, distributers, or installations. Consumers dissatisfied with DG equipment are limited to seeking redress through the same channels as other consumer products; that is through the AG, Better Business Bureau, courts by civil litigation, etc. There is regulation of installers, but customers do not have assurance that the installers have appropriate training in DG installations.

Consumer Advocate
The AG's office handles DG consumer complaints and Iowa law provides statutory remedies that are appropriate to address the issues presented.

IAEC
The Consumer Protection Division of the AG's office should address DG consumer complaints.

ELPC et al.
The Iowa AG's office is responsible for enforcing consumer protection complaints regarding DG suppliers and distributers in Iowa, this channel has been effective with issues that have arisen to date.

All Points Power
Current Iowa Consumer Protection laws provide for filing complaints against vendors and suppliers.

Energy Consultants Group
The Board is not the best entity to protect consumers, given the long relationship with utilities companies. An agency not tied with state or utility companies would be ideal to resolve consumer complaints.

Jason Hall, Jean Marie Hall, Jenn Hall, Kami Ahrens, and Moxie Solar
The Board should have jurisdiction to resolve any consumer complaints.

John E. Carpenter
Speaking to his experience in Minnesota, Mr. Carpenter was on his own with the installer contract and with the utility.

Industrial Energy Applications
Commercial complaints should be directed to the AG. Complaints related to tariffs, interconnection, etc. should be directed to the Board.

5. Should DG suppliers/distributors be required to be certified as qualified to supply/install the equipment/project in question? Who should perform the certification? Who, if anyone, should maintain a listing of certified DG contractors/installers?

IPL
IPL supports the certification of DG suppliers/distributors/installers in the State of Iowa. An increase in knowledgeable and safety conscious installations will benefit the customer and the utility. A suggested certifier would be the NABCEP, which provides professional certification in the fields of PV installation, PV Technical Sales, Small Wind Installer, and Solar Heating Installer.

MidAmerican
If DG is to be a substitute for utility generation, then it is appropriate to regulate all aspects of this supply. However, if DG is not intended to be on the same caliber as utility generation then a reduced level of utility regulation may be sufficient. If the Board wants to continue to advance DG, it is appropriate for the Board to regulate parts of the DG process, such as DG device supply and installation. The Illinois Commerce Commission implemented a simple certification process for DG installers that became effective as of January 1, 2014. The act of certifying installers or suppliers will not involve the Board in professional regulation, but instead in the determination of the types of skills that must be maintained. Handling of complaints about DG installers, distributors, and suppliers would be a logical extension of the certification responsibility, as would maintenance of lists of certified DG contractors/installers.

Consumer Advocate
IPL's renewable energy pilot program approved in Docket No. EEP-08-1 included provisions to help assure that customers interested in DG installations would have access to reliable technical information. For renewable energy site assessments, the

assessor must be trained according to training standards established by the Midwest Renewable Energy Association. This quality assurance process could be part of the renewable energy education, outreach, and training that will be furnished by Iowa's IOUs.

<u>IAEC</u>
The IAEC believes that rules established for natural gas providers are a good starting point to mirror in establishing certification requirements for DG suppliers/distributers.

<u>IAMU</u>
The IAMU believes that DG suppliers and distributers should be subjected to mandatory certification. If a list is maintained of certified contractors/installers it should be done by an unbiased third party.

<u>MRES</u>
MRES members have already seen poor and improper installations of units. There should be rules and provisions pertaining to DG distribution and installation.

<u>ELPC et al.</u>
ELPC et al. believe that existing rules already provide sufficient consumer protection. If the Board chooses to require installer certification, ELPC et al. recommend relying on NABCEP or another nationally established and well respected certification program. Installer certification can be a useful consumer protection measure in early-stage markets, but it can also be abused in anti-competitive ways, for example by municipal utilities requiring and charging fees for community-specific licenses. Since DG installers operate regionally, this can be a major market barrier.

<u>ESA</u>
Licensing requirements and certification for installers is important to protect consumers and energy storage developers from unqualified service providers.

<u>ISETA</u>
ISETA supports a licensing requirement to deal with safety issues.

<u>Sierra Club - Iowa Chapter</u>
NABCEP provides a reliable certification program that could be used for certification of DG suppliers and distributers. The Sierra Club - Iowa Chapter provided its fact sheet on certification of dealers, site assessors, and installers as an attachment to its comments. The Board should maintain a listing of certified DG contractors/installers.

<u>All Points Power</u>
Current interconnection standards and other rules and codes require that a licensed electrician sign off on a completed project. Local municipalities require final inspections and state inspectors are responsible for final inspections in outlying areas. The issue of licensing suppliers and vendors may be a good marketing ploy, but is not required to ensure safe and reliable installation of DG systems.

Energy Consultants Group
Energy Consultants Group encounters daily issues of plants not functioning properly or that are unsafe from DG plants that they do not own. As demand increases, negligence and incompetence in this industry is growing. Adoption of the NABCEP program in Iowa is a good step to ensure quality systems. The State Fire Marshal's Office should regulate and provide license to install these systems. A state license should be required that includes continual education and annual audits to uphold install/design status in Iowa.

Jason Hall, Jean Marie Hall, Jenn Hall, Kami Ahrens, and Moxie Solar
DG suppliers and distributers should be required to be certified in Iowa. Iowa-based community and technical colleges should administer certifications. The Board should maintain the list of certified suppliers and distributers.

John B. Cook
The Board should keep a list of certified DG contractors similar to the state maintained list of certified radon testers and mitigation installers.

John E. Carpenter
DG installers should be certified in the same manner as electricians; however DG designers and installers do not need to be licensed electricians. The State Commerce Division should maintain lists of certified DG designers and installers.

Larry A. Stone
DG suppliers and distributers should be required to be certified in Iowa. The Board should maintain the list of certified suppliers and distributers.

Industrial Energy Applications
There are plenty of protections for the consumer in the form of state and local regulations. From a safety standpoint, the current interconnection rules and other state rules require sign-off by an electrician licensed by the State of Iowa. The licensing requirement for these electricians is rigorous. An electrician is not going to risk their license by performing a substandard installation. Local municipalities and utilities have inspection jurisdiction over these installations before the system is energized. Additional bureaucracy in the form of licensing or certifications is not needed. A supplier/installer is incented to do a good job of installation by the future word-of-mouth advertising that they will receive (good or bad).

William J. Pardee
Mr. Pardee supports certification requirements for DG suppliers/distributors, but does not speak to who should be responsible for the certification.

Summary of Responses to General Questions

1. **For calendar year 2013, provide the following detailed information (in an Excel file) related to each DG facility connected to your utility system:**

2. **Should Iowa have a policy goal to increase and diversify alternate energy production? If so, should that policy be achieved with utility- owned centralized generation, utility-owned distributed generation, customer-owned distributed generation or a mix of these alternatives? Discuss the advantages and disadvantages of these approaches.**

IPL
The state has already enacted policies that either directly or indirectly encourage a diverse and cost-effective generation mix. The power supply portfolio in the state has become much more diverse. Policy goals to increase smaller scale alternative energy production should be compared against these utility scale developments to determine the most cost-effective way to achieve desired goals. In general, IPL believes the state is wise to continue its existing policies that have resulted in a diverse power supply in the state and to use the experiences of other states to drive policy and other decisions as it relates to the further development of policies for smaller scale (AEP) deployment.

MidAmerican
Iowa should continue to have a broad approach to energy supply and consider all resources including, but not limited to, energy efficiency, natural gas, and utility and customer-owned wind, solar, and other renewables to help address future energy needs. Iowa's policies should continue to be focused on reasonable low cost resources, taking into account impacts on customer rates when achieving a proper balance of resources. Iowa's policies should address barriers to encourage investment with emphasis on minimizing rate impacts on customers.

Consumer Advocate
Iowa has a policy goal to increase AEP[76] which has targeted certain types of DG and associated diversification attributes through technology-specific tax incentives. Iowa's advance ratemaking principles statute[77] also allows consideration of diversification and associated environmental and cost attributes that are presented by various generation expansion alternatives. For customer-owned DG, diversification considerations and objectives can be reflected in technology-specific avoided cost rates.

DG provides ample quantifiable and non-quantifiable benefits for both the utility system and utility ratepayers which should be reflected in the calculation of avoided cost rates for utility purchases from QFs. One advantage of customer-owned DG is that the generator is only paid for actual generation and they are responsible for operations and maintenance to achieve good production performance in order to receive payment.

[76] Iowa Code § 476.41.
[77] Iowa Code § 476.53.

IAEC
Policies adopted by the Iowa Legislature may incent certain types of ownership or business models but the IAEC does not believe the Board should enter into this business.

IAMU
Public power utilities operate to strengthen their communities by providing low-cost reliable power through strategic long-range planning which will continue to include new tools to analyze the costs, benefits, and infrastructure requirements of DG installation. The municipal utilities must retain local control to set their own policy goals due to the variations in loads and size. Some municipal utilities and utilities that are members of Joint Action Agencies are already doing resource planning that includes diversification of resources and significant amounts of AEP.

For municipal utilities, the advantages and disadvantages of utility-owned centralized generation, utility-owned DG, customer-owned DG, or a mix will be dependent upon individual factors that are unique to the community and to the utility. Utility control of DG installations like utility community solar gardens will generally have lower project costs through greater economies of scale than DG spread out over various customer locations. Utilities are in the best position to select projects that align with their unique power supply needs.

MRES
Iowa has had a long-standing focus on renewable energy and has done so with tax incentives already in statute. The federal EPA issued proposed rules pertaining to CO_2 emissions from existing generating resources. Iowa should focus on an efficient energy delivery system that takes into account meeting the CO_2 mandates, promoting energy efficiency, and maintaining high reliability at the most cost-effective level possible for the customers. The Board should work with the utilities on what works best for their customers and for reliability from an overall perspective.

TASC
There is no credible evidence to suggest that regulated utility participation in the DG market would benefit participant customers or ratepayers. True competitive markets are defined by the existence of a level playing field, the internal information and resources the utility has access to disrupts the equilibrium of the market should the utility be permitted to participate. Further market distortion can occur by the ability of regulated utilities to rate base assets and earn a guaranteed rate of return, an advantage that no other participant would enjoy. The connections that utilities have with customers in the form of information distribution and web sites for billing regulated services give an additional advertising advantage. For these reasons TASC believes that participation of monopoly utilities in the DG market will undermine competition. However, TASC is not opposed to an affiliate of a utility entering the solar market subject to robust affiliate transaction rules and appropriate regulatory oversight designed to ensure the affiliate cannot leverage the information and other advantages of the monopoly utility.

ELPC et al.
Iowa has a clear statutory policy goal to increase and diversify AEP. The Board should look at policies that encourage a range of options for building alternative energy and should not create barriers to any particular option for developing alternative energy. Public policy in Iowa has supported customer-owned wind DG with state production tax credits. Similarly, if Iowa utilities were interested in developing additional utility-owned renewable generation whether it is centralized or distributed, ELPC et al. would encourage and support those efforts. The Board should continue to implement Iowa's policy to encourage alternative energy production and support a mix of options to accomplish the goal.

ESA
Energy policies should incentivize diversification of energy sources, including alternative energy and innovative technologies. Utility as well as third-party ownership models for energy storage deployment should be considered as viable; preferring one particular construct over another can limit access to markets and restrict innovation.

Sierra Club - Iowa Chapter
Iowa should have a policy to increase and diversify AEP. The Sierra Club – Iowa Chapter supports all forms of AEP, of all sizes, and on both sides of the meter, and owned either by the utility or the customer.

Utility-owned centralized renewable energy generation may be necessary to supply sufficient capacity to cities or areas that do not have the ability to generate enough alternate energy on their own. Disadvantages of utility-owned centralized DG are the loss of power over the transmission lines and that customers must purchase all of power from the utility. Utility-owned DG would allow the utility to obtain revenue from DG and allow customers who cannot afford to buy the wind generators or solar panels to get some benefit from DG.

Customer-owned DG is the most beneficial to the customer, especially with a FIT or net metering that would make it more cost-effective.

Ben Grimstad
Iowa should utilize all alternatives suggested in the question to protect earth and reduce CO_2 emissions. Additionally fossil fuels will become more expensive as the supply is reduced over time.

Decorah Solar Field, Frank Belcastro, Jason Hall, Jean Marie Hall, Jenn Hall, Kami Ahrens, Moxie Solar, and William H. Ibanez
Iowa should have a policy goal to increase and diversify AEP which will attract youth, progressive people and companies, and financial capital. Utilities will not build alternative energy facilities unless forced to do so through competition from individual or community-wide DG sites utilizing virtual net metering and FITs.

The advantage of using locally owned individual or community DG sites is that it creates an awareness of the value of energy within the community. Local investors are more willing to pay for the transition to clean renewable energy and grid changes because they are closer to the DG activity.

<u>All Points Power</u>
Iowa's goal should be to foster diversity, flexibility, a reduction in environmental impacts, and cost competitiveness. Competition is an important aspect of diversity since it allows for a mixture of market participants. DG creates a more fault tolerant, robust electrical grid while reducing fossil fuel consumption. Encouraging customer-owned DG will create a more attractive business environment in Iowa.

<u>Luther College Wind Energy Project LLC</u>
Iowa currently has a policy goal to increase AEP[78] but the Board could further support this goal by expanding the current net metering policy and requiring utilities to offer FITs. Systems that reduce peak demand should be prioritized and those that include energy storage should receive additional compensation. Generators should be able to choose to retain the renewable energy certificates for sale to a third party or to bundle them with the power for sale to the utility.

<u>Luther College</u>
Iowa does not need a policy goal to increase and diversify AEP. Iowa should strive for a mix of utility and customer-owned DG systems. The increasing amount of EPA regulation will drive utility interest and declining cost for PV systems will drive customer interest. Any policy to increase and diversify AEP needs to value the interest of customer-owned DG as much or more than the interests of the utilities.

<u>John B. Cook</u>
The policy should include utility- owned centralized generation, utility-owned DG, customer-owned DG or a mix of these alternatives.

<u>John E. Carpenter</u>
Iowa should have a policy goal to increase alternative energy production that does not pump CO_2 into the air from fossil fuel resources or make radioactive waste. A mixture of DG ownership options is the most reasonable approach but utility ownership is the most powerful way to increase alternative energy production because they have the necessary capital and can plan the infrastructure.

<u>Larry A. Stone</u>
Iowa should have a policy goal to increase and diversify AEP which could make Iowa a leader in alternative energy and attract environmentally friendly economic development.

<u>Iowa Chapter - Physicians for Social Responsibility</u>
The Board has the responsibility to protect all Iowans and society is being harmed by CO_2 and the many other toxic pollutants fossil fuels produce adversely affecting air and

[78] Iowa Code § 476.41.

water quality. Similarly, society is being harmed by the increasingly extreme measures used to extract and process fossil fuels. DG encourages investment in renewable energy and reduces in the harms associated with fossil fuels.

Utilities are also subject to economic uncertainty about the costs of reducing emissions, the costs of extracting coal or gas, the costs and risks of managing their waste, difficulty maintaining transmission capability in the face of extreme weather events. Current environmental and social realities mean the utility business model is failing.

The Board should improve and expand on what others have already put in place rather than create a new policy. Workable solutions to distributed energy have been adopted in many other states and nations. It's time that Iowa move forward and do its fair share in creating a livable and life sustaining future world.

Industrial Energy Applications
Iowa's goal should be to foster diversity, flexibility, environmental impact reduction, and cost competitiveness. Competition and a mixture of all participants in a more open market benefits all class of customers, lessens the utility monopoly on generation and may invite in independent power producers. A more wide-open market would help foster DG adoption and its corresponding financial, environmental, and societal benefits enumerated in prior responses.

EcoWise Power
Iowa needs a statewide, consistent policy to include electric customers served by RECs and municipal utilities that would facilitate participation by all interested Iowans in DG investment and enable them to take advantage of expiring federal and state incentives.

Robert Fischer
The Board should set a goal for increasing the generation of clean and renewable energy wherever possible and encourage DG and virtual net metering.

William J. Pardee
Iowa should have a policy to increase solar and wind energy production. Diversified, customer-owned DG systems reduce the capital needed by utilities and are more robust against economic and environmental uncertainty.

The utilities' traditional business model is failing. The utilities have a new role to play, as one of many providers and perhaps as the operator of the grid. Attempting to force the traditional monopoly role of utilities to work in this changing world will produce a disaster for customers and utilities alike. Centralizing DG restricts customers' desire for influence on their own energy future, loses the benefit of customer supplied capital, and loses the resilience of true DG.

The Board regulates Iowa utilities for the benefit of Iowa residents, not the other way around. Iowa residents want less CO_2, less pollution, more solar and wind energy, and some control over their future energy costs. DG is an important component to meeting those goals.

3. What are the current incentives, if any, for the utility to promote DG and for the customer to own DG? Should alignment of DG production with utility peak demand be the target of an incentive?

<u>IPL</u>
Utility incentives today are in the form of market development/understanding and good will. Net metering may fit the definition of customer incentives. Providing additional customer incentives should depend on the policy goals. All other things equal, IPL prefers a pricing system which places all forms of generation on a level playing field and minimizing costs to customers over the long-term.

Incentives (payments) aligning with a utility peak should be based upon the value the utility receives from its Regional Transmission Operator or power pool for that generation. DG production coincident with utility system peaks should result in a higher valuation of the DG output, as long as MISO provides the utility Zonal Resource Credits. If small DG is not eligible for Zonal Resource Credits, there may not be additional incentives for the coincidence with the utility system peak, only an energy credit.

<u>MidAmerican</u>
The current DG rate structure and net metering policies discourage and create barriers for MidAmerican to promote and integrate DG into the grid. Customer/utility collaboration in projects such as local solar installations owned, operated, and maintained by MidAmerican would allow for optimal location and maximum resource mix while minimizing adverse reliability and safety impacts.

As to the question concerning whether alignment of DG production with utility peak demand should be the target of an incentive. In the proper rate structure, DG customers consider energy production and reduced peak demand and customers may conclude that it is in their best economic interests to optimize peak demand and energy production in total rather than just maximizing energy production.

<u>Consumer Advocate</u>
Apart from legal mandates, a current incentive for the utility to promote DG is the contribution toward the utility’s resource portfolio, allowing the utility to avoid short-term incremental costs and potentially avoid additional generation investments. DG resources help the utility shift the economic dispatch stacking of the resources necessary to serve different loads in different periods. For example, PV resources lower the need to dispatch more expensive generation resources during peak periods.

Current incentives for a customer to own DG are primarily financial in that DG allows a customer to reduced energy consumption from the utility. There is also compensation for selling energy resources to the utility electric system based on the avoided cost of energy and capacity of the utility, avoidance of utility service interruption, and rate stability and predictability.

The target of incentives should not be based solely on DG production during peak demand periods. Depending on the time of day and the season, the value of a resource will vary. Wind energy typically provides little value during summer peak seasons but during high capacity periods wind energy provides a valuable resource to help minimize a utility's average variable cost. Peak output from PV technologies occurs during the utility's summer peak demand period. Incentives should be based on the value a resource can be expected to provide a utility based on its generation characteristics.

<u>IAEC</u>
The incentive for a utility to promote customer-owned DG varies depending on the utility's capacity, transmission and distribution constraints, etc. There may be circumstances where DG investment is beneficial but there may also be instances that result in stranded or increased costs. To the extent government is involved in providing incentives, it would seem logical that incentives that match demand and supply would be most preferred.

<u>IAMU</u>
Each municipal utility evaluates what incentives to provide depending on local conditions, including available local funds, community interest, and availability of the DG resources. Community solar development would benefit from shared solar tax credits being made available to municipal utilities.

<u>MRES</u>
Each municipal utility evaluates the incentives it will provide, based on local conditions.

<u>ELPC et al.</u>
Currently there is a mix of state and federal incentives for customers to own or install DG, such as federal and state tax incentives, loans and grant programs, and utility incentives. The eligibility for these incentives can vary widely, meaning a customer may only be eligible for one or two of the available incentives.

ELPC et al. suggest that utility incentives focus on maximizing the value of DG overall. A comprehensive DG study will identify and quantify these benefits and costs and allow for incentives to be designed to maximize these values. Aligning DG production with utility peak demand is one of these values and should be considered in the context of all values rather than alone.

<u>Sierra Club - Iowa Chapter</u>
Alignment of DG production with utility peak demand should be the target of incentives since reducing peak demand reduces costs to all customers.

<u>Decorah Solar Field, Frank Belcastro, Jason Hall, Jean Marie Hall, Jenn Hall, Kami Ahrens, Moxie Solar, William H. Ibanez</u>
Currently, there are no incentives for utilities to promote DG. Federal and state tax incentives will pay up to 48 percent of solar project cost in Iowa and United States Department of Agriculture Rural Energy for America Program (REAP) grants, for farmers and small rural businesses, are available for up to 25 percent of the project costs. These incentives combined with net metering provide a system payback of ten years or less.

<u>All Points Power</u>
Current incentives for customers include tax incentives for renewable generation, but are more limited for CHP/WHP, peak shaving, interruptible power, etc. Peak load reduction is a significant benefit of DG, especially through CHP/WHP projects, as is VAR support.

<u>Energy Consultants Group</u>
All utilities should offer performance-based cash rebate incentives for DG plants verified by a certified professional.

<u>Luther College</u>
IPL currently does not offer incentives encouraging DG investments. Solar PV and natural gas-fired CHP systems can contribute to peak power production and should be incentivized. Utilities should also provide incentives for energy storage systems when they become cost effective and commercially available.

<u>John B. Cook</u>
The EPA's emission reduction plan is a significant incentive for utilities to increase AEP and DG is one way to do that. REC's mission is to serve their member/customers and promoting and facilitating DG can help them fulfill that mission. Incentives for customer ownership include tax credits, favorable return on investment, and a desire to slow global warming.

<u>John E. Carpenter</u>
The utility has very little incentive to promote customer-owned DG. There may be some incentive if utilities could negotiate aggregation of renewable energy credits with its customers.

<u>Industrial Energy Applications</u>
Utilities are neither incentivized nor dis-incentivized to pursue DG as an investment strategy. Understandably utilities do not foster DG incentives for their customers, as it represents an erosion of their customer base just as having energy efficiency programs does. As a result, tax incentives are a better means of transferring benefits to DG adopters.

Peak demand is certainly one of, but not the only viable target for DG. CHP can help reduce base load projects. DG and CHP can both assist with grid stabilization and voltage support, particularly as utilities close down smaller coal plants and combustion turbine peaking plants.

Wendy VanDeWalle
The Board should require the utilities to have rebates for solar and wind DG. It doesn't make sense to have rebates for a washing machine but not for a solar array. The IPL renewable rebate was the key in allowing us to install solar and should not have been discontinued.

William J. Pardee
Customers frequently install solar and wind to reduce the negative costs associated with fossil fuel extraction and as an effort to stabilize future energy costs.

Utilities face economic uncertainty about the costs of reducing emissions, the costs of extracting coal or gas, the costs and risks of managing nuclear waste, the difficulty in maintaining the transmission capability in the face of extreme weather events, and declining demand as consumers choose DG. The utility business model is failing and they need help to find a new role.

It seems fair to use time of day metering and pricing with net metering to align utility peak demand with DG, though the DG system has little real control over time of production.

4. Do utilities include distributed generation in their resource planning? If so, how is DG accounted for? If not, why and is this likely to change?

IPL
The amount of DG on IPL's system is relatively small if the DG used comply with the interruptible program is excluded. In the near term, the expected amounts of DG are not expected to be great enough to justify an explicit forecast of DG applications. If DG has affected sales, this would be reflected in the actual historical sales levels andwould therefore impact the future load forecast. Sensitivity testing of the plans with lower load forecasts would be reflective of greater amounts of DG, amongst other factors.

MidAmerican
MidAmerican includes DG in capacity credit planning to the extent such resources can be registered with the MISO. In order to be eligible for capacity credits, MidAmerican, as the market participant, must own or have contracts with the capacity resources and register these resources with MISO. DG assets registered with MISO for capacity credits as a Load Modifying Resource would need to have an obligation to be made available during emergencies. While MidAmerican has some behind the meter generation that meets these requirements, this would likely not be the case for small DG installations.

Peak demand and energy forecasts for load are net of DG not registered with MISO. Historical load data includes energy production from non-registered DG. New forecasting methods to include DG as a separate forecast may be required if there are significant increases in the amount of DG.

Consumer Advocate
In the recent avoided cost workshops in Docket No. INU-2014-0001, MidAmerican and IPL described modeling DG as a net load impact in its integrated resource plan process by subtracting it from a gross load growth projection. At the same time, many utilities are considering DG to be modeled as a generation resource option, rather than a net load impact.

IAEC
To the extent that historical load data is used to develop load forecasts, the existence of DG impacts resource planning.

IAMU
Municipal utilities are evaluating best practices for integrating DG into their resource options. Currently the typical resource mix depends on long-term contracts, generation ownership, and participation in a Joint Action Agency that owns or contracts for resources.

MRES
Joint Action Agencies and their municipal utility members are engaged in evaluation of the best practices for integrating DG into their resource portfolios.

TASC
TASC is unaware of utilities including customer-owned DG in their resource planning but believes that utilities need to start accounting for customer-sited generation and load to ensure that future transmission and distribution asset investments are prudently incurred. Reformation of utility planning will enable utilities to account for emerging DG systems and plan accordingly, facilitating additional customer adoption of DG.

ELPC et al.
Currently, MidAmerican and IPL do not include DG or energy efficiency as resources in their plan but instead reflect them in their load forecast which undervalues DG resources in a variety of areas such as avoided cost calculations and integrated resource planning.

The decline in the cost of solar resources indicates the possibility that solar generation in Iowa will be a cost-effective resource in the near future. NREL recently published a report on the possibility of solar as a cost-effective resource impacts resource planning[79] and concluded that most responsive utilities treat DG as a net load impact rather than a resource. This option makes it difficult to capture the direct impact of distributed solar on the system. Another option that some utilities incorporate involves

[79] See generally NREL, Treatment of Solar Generation in Electric Utility Resource Planning (2013).

treating DG as a generation resource explicitly. This can enable an independent investigation of customer load profiles, which can be more effective in long-term planning.[80] Utilities could then more effectively incorporate DG into their resource planning.

This docket should look at how Iowa utilities can take steps to treat DG as a resource and appropriately incorporate DG into their integrated resource planning. This requires thinking about a number of issues that Iowa has the opportunity to work through in a thoughtful way before significant amounts of DG are on the grid and the Board should take advantage of this opportunity.

<u>ESA</u>
As Iowa utilities develop annual reports detailing their planning process to meet future load requirements, energy storage technologies and applications should be one of the options that can meet system needs. The number of energy storage projects demonstrated and tested by utilities and third parties has dramatically increased. The operational data from these collective projects should allow for a greater level of comfort as utilities integrate energy storage into the daily operation of their systems.

As states begin to determine how best to meet greenhouse gas emission targets, energy storage will become a critical tool. Ensuring diversity of the resource mix in this transition will necessitate fully leveraging the range of benefits energy storage can supply.

5. What is the rate of DG adoption currently experienced by each utility and what is the rate projected to be in the next five to ten years? Do these adoption rates cause problems with transmission and distribution planning? How do utilities cope with this challenge?

<u>IPL</u>
IPL is not able to project at what rate the penetration will continue as the historical adoption rate has been influenced by IPL's Efficiency First Renewable Rebates pilot and the future will likely be influenced by the continuation of declining equipment costs and the availability of tax incentives and the REAP grant.

IPL is working with ITC Midwest and MISO on policies and procedures to ensure DG is not impacting the operation of the transmission system. From a distribution planning perspective, entire feeder voltage and load support based on century-old electric design needs to be re-evaluated.

<u>MidAmerican</u>
MidAmerican has 156 DG facilities on the system with 139 under the net meter tariff. While interest in solar rooftop facilities has increased over the last few years, MidAmerican does not have projections nor has it determined a level where

[80] Id. at 25.

transmission and distribution planning issues may appear. Now is the time to address DG issues before penetration levels cause potential reliability and system planning issues, and before cross-subsidization issues create significant rate increases for customers who do not have DG facilities.

DG is just one of the many issues utilities deal with on a day-to-day basis as we plan and operate the electric system and deliver energy supply to our customers. The plans developed to achieve our goal of being the best energy company in serving our customers, while delivering sustainable energy solutions, typically include addressing possible impacts of many variables, such as environmental policy and regulations, load growth, wholesale electric prices, projected coal and natural gas prices, costs of materials and supplies, and many other factors.

IAEC
Due to the numerous variables, the RECs have not made formal projections on adoption rates. Load forecasts, to a certain extent, take into account adoption rates for DG.

IAMU
At this time, the rate of DG adoption is low among municipal utilities. Municipal utilities are working with the IAMU and their Joint Action Agencies to develop tools needed to optimize DG installations such as a checklist of distribution system impacts and mitigation for DG adoption. The Board and the Organization of MISO States may wish to initiate discussion with MISO and transmission owners to determine the impact of significant DG on the costs and benefits of high voltage transmission investments.

As DG becomes more prevalent, municipal utility leaders will need to develop a new business model that recognizes the value of DG while at the same time provides compensation to cover the fixed costs of the grid, including distribution, transmission and generation facilities, necessary to maintain current levels of reliability.

MRES
The rate of adoption of DG within MRES Iowa member communities is low, but is unpredictable. The future rate of adoption may be positively impacted as more members implement the DG interconnection workbook of MRES or that of the IAMU.

ELPC et al.
It is difficult to track the DG market and adoption rate in Iowa on a statewide basis due to the numerous utilities in Iowa. ELPC et al. believe the adoption rate for DG technologies like solar PV in Iowa is currently slower than most states and significantly slower than leading states.

At the current rates of DG adoption, we would not expect any problems with transmission and distribution planning, but the evidence suggests that problems occur only at very high deployment levels and should thus not be an issue in Iowa now or in the foreseeable future.

In order to project a DG adoption rate for Iowa, a study could be conducted that takes into account the existing policies, electricity prices, empirical evidence from similarly situated jurisdictions, and future expectations for policies. Although this study could be difficult, a general idea of a future adoption curve for DG could then be used in transmission and distribution planning.

General Comments

IPL

IPL continues to strive to understand DG's impact on all of its customers and the utility business model. As DG technology develops, IPL's objective is to actively engage in the effort to meet the energy goals of its customers while maintaining its on-going emphasis on exceptional safety, reliability, and affordable energy for all customers.

IPL must balance many interests. While IPL is supportive of developing an understanding of how to enable deployment of safe, reliable and affordable DG resources, these activities should not be done with the sole purpose of maximizing DG deployment without consideration of costs, benefits, or other factors that impact both participating and non-participating customers. IPL is expected to use thoughtful due-diligence so that prices paid for utility service are reasonable, and the prices paid for DG may have an impact on this equation moving forward. IPL supports the potential development of DG, advocating for a thoughtful approach demonstrated through these guiding principles.

ELPC et al.

DG provides benefits that extend beyond the location of a project. With DG, energy is used where it is produced, making it more efficient because energy is not lost over transmission and distribution lines. DG diversifies energy which contributes to grid stability, conserves resources, creates jobs, and reduces emissions that result in environmental and health benefits. DG growth presents new challenges and opportunities for utilities that will require collaboration by all stakeholders to incorporate best practices and improve Iowa policy and update business models to incorporate DG.

The Board should create a uniform set of expectations and requirements for the DG market in Iowa by extending Iowa's net metering and interconnection standards to all RECs and municipal utilities in the state. Other high priority recommendations include: expanding or eliminating the net metering system size cap; and updating Iowa's interconnection standards to reflect new best practices, including those adopted recently by FERC. The Board should conduct a comprehensive value-of-solar analysis to help the future direction for DG policy in the state.

ESA

While energy storage does not fall under the DG definition given for purposes of this inquiry, the ESA believes that it is a critical resource to the DG discussion and should be a part of the Iowa DG plan.

Winneshiek Energy District

Advances in distributed energy are occurring within the context of the most rapid transformation of the U.S. electricity system since the first half of the 20th century eating into utility sales and income and challenging grid management. Utility rates rise in an attempt to cover fixed costs and keep profits steady for investors, in turn encourages even more DG.

The energy world is rapidly changing, there is increasing awareness that the electric utility industry is facing inevitable change. Europe started down the road toward customer and community-owned renewables before the United States, and resistant utilities are now facing the worst structural crisis in the history of energy supply. In May 2014 Barclays downgraded the entire U.S. electric sector bond market to underweight[81], stating:

> In the 100+ year history of the electric utility industry, there has never before been a truly cost competitive substitute available for grid power. We believe that solar + storage could reconfigure the organization and regulation of the electric power business over the coming decade. We see near-term risks to credit from regulators and utilities falling behind the solar + storage adoption curve and long-term risks from a comprehensive re-imagining of the role utilities play in providing electric power.
>
> Valuations suggest credit investors are depending on the regulatory compact, (whereby the monopoly utility agrees to invest in assets to service customers in return for prices that are set to allow them a reasonable return) to give sufficient protection from industry changes. While the regulator/utility construct has usually resulted in low-risk returns to credit in the past, technological change creates precisely the environment where slower-moving incumbents and their regulators can fall behind the curve, risking credit volatility, or disrupt the regulatory compact, possibly leading to unexpected losses for bondholders. Investors may be also wary of optimism about solar power, given a recent history of losses in that industry. We believe that sector spreads should be wider to compensate for the potential risk of regulator missteps and/or a permanent change in the utility business model.

Five years ago DG and customer-owned solar were fringe discussions in the energy world; today they threaten utility business model viability. Customer-owned storage was likewise a fringe discussion which also soon may threaten the future viability of the grid.

[81] As quoted on Barron's Blog: http://blogs.barrons.com/incomeinvesting/2014/05/23/barclays-downgrades-electric-utility-bonds-sees-viable-solar-competition/.

The most urgent question facing us is not so much a potential utility death spiral, but a grid death spiral.

Energy democracy, grid defection, local ownership, and energy independence are becoming increasingly economically viable for customers and communities to cut the cord with the grid as it exists today. Current regulatory actions will create conditions contributing to either rapid grid evolution or grid disintegration. Actions increasing the administrative and/or economic burdens on DG owners will inevitably contribute to the latter.

The Board should consider the current issues of net metering and interconnection within this context. Significant questions include:

- What is the value of solar?
- What is a fair and just relationship between utility and customer or community?
- What is the Value of the Grid?

Community renewable energy options encompass both the net metering and interconnection aspects of the current comment request. They solve many problems: renewable energy ownership and on-bill credit for those not able to install behind their own meter; transferability; single interconnection versus dozens to thousands; multi-year distribution planning opportunity; and long-term grid connectivity versus grid defection. It is strongly recommended that Iowa move forward with enabling policy on community or shared renewable energy options.

The Utility Community Solar Handbook included in the current Board order focused on just one type of community renewable energy (in this case specifically solar) project: those owned by the utility.

Important in the context of this docket, is understanding the customer’s and community's motivation for desiring a community solar program. Client responsibility and localism have been significant drivers of DG, and will continue to be well into the future. It helps little that the electric utility industry as a whole has been strongly anti-DG and universally resistant to climate action throughout Iowa and the country.

The extensive benefits of community renewable energy projects mentioned earlier are unlikely to be realized by utility-owned community solar projects, any more than their green power options were bought by customers. For these benefits to be realized, community renewable programs should follow key guiding principles, as described in the IREC’s Model Rules for Shared Renewable Energy Programs (submitted together with these comments):

1. Shared renewable energy programs should expand renewable energy access to a broader group of energy consumers, including those with limited resources to build their own DG systems.
2. Participants in a shared renewable energy program should receive tangible economic benefits on their utility bills.
3. Shared renewable energy programs should be flexible enough to account for energy consumers' preferences (including business and ownership models).
4. Shared renewable energy programs should be additive to and supportive of existing renewable energy programs, and not undermine them.

Community renewables are an opportunity to meet many of the needs and motivations of customers within the context of grid integrity, when implemented per the above principles. The moral and economic imperative of addressing climate change and the societal inevitability of increasing energy democracy, suggest strengthening Iowa policies promoting renewable energy production. A combination of ownership structures will best create rapid energy evolution. Customer, community, and third-party owned DG must be prioritized, however, to maintain maximum grid participation and inclusiveness.

<u>Craig Mosher, Larry Grimstad, Frank Belcastro, Jason Hall, Jean Marie Hall, Jenn Hall, Kami Ahrens, Larry A Stone, Tim Brodersen of Moxie Solar, and William H Ibanez</u>
The dangers of global climate change require reducing the use of fossil fuels as quickly as possible. DG reduced the need for new power plant construction and balances the grid. The Board should facilitate DG and community solar so that more customers can participate. Utilities need to modify their business models just as the phone companies did. DG is a vehicle to reduce greenhouse gas emission levels.

<u>Iowa Chapter – Physicians for Social Responsibility</u>
Hurdles to DG growth are based on bureaucratic rules supporting centralized fossil fuel-based energy monopoly utility providers. The Board has a responsibility to all Iowans and needs to consider the important health, ethical and justice issues related to DG.

All of society carries the cost of CO_2 in our atmosphere as well as the many other toxic pollutants produced by fossil fuels. The harms and consequences associated with fossil fuel extraction can only be expected to grow. DG encourages investment in renewable energy and reduction in the harms associated with fossil fuels benefitting all of society current and future.

Current environmental and social realities associated with the environmental and social costs utilities are facing indicate that the current utility business model is not sustainable. It's time for Iowa to move forward in building and improving distributed energy.

Steve Demuth
The Board should adopt policies to lead to energy self-sufficiency. Iowa has adequate resources and combined with good planning should be able reach this goal in 10-15 years.

Wendy VanDeWalle
The Board has a responsibility to promote renewable energy and DG. Utilities should be required to have rebates for solar and wind DG, it makes no sense to receive a rebate for a washing machine and not DG.